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Volume II: Coal

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from
the
West

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FORWARD

The production of electricity and fossil fuels inevitably impacts Man and his environment. The nature of these impacts must be thoroughly understood if balanced judgements concerning future energy development in the United States are to be made. The Office of Energy, Minerals and Industry (OEMI), in its role as coordinator of the Federal Energy/Environment Research and Development Program, is responsible for producing the information on health and ecological effects - and methods for mitigating the adverse effects - that is critical to developing the Nation's environmental and energy policy. OEMI's Integrated Assessment Program combines the results of research projects within the Energy/Environment Program with research on the socioeconomic and political/institutional aspects of energy development, and conducts policy - oriented studies to identify the tradeoffs among alternative energy technologies, development patterns, and impact mitigation measures.

The Integrated Assessment Program has supported several "technology assessments" in fulfilling its mission. Assessments have been supported which explore the impact of future energy development on both a nationwide and a regional scale. Current assessments include national assessments of future development of the electric utility industry and of advanced coal technologies (such as fluidized bed combustion). Also, the Program is conducting assessments concerned with multiple-resource development in two "energy resource areas":

- Western coal states
- Lower Ohio River Basin

This report, which describes the technologies likely to be used for developing six energy resources in eight western states, is one of three major reports produced by the "Technology Assessment of Western Energy Resource Development" study. (The other two reports are an impact analysis report and a policy analysis report.) The report is divided into six volumes. The first volume describes the study, the organization of this report and briefly outlines laws and regulations which affect the development of more than one of the six resources considered in the study. The remaining five volumes are resource specific and describe the resource base, the technological activities such as exploration, extraction and conversion for developing the resource, and resource specific laws and regulations. This report is both a compendium of information and a planning handbook. The descriptions of the various energy development technologies and the extensive compilations of technical baseline information are written to be easily understood by laypersons. Both professional planners and interested citizens should find it quite easy to use the information presented in this report to make general but useful comparisons of energy technologies and energy development alternatives, especially when this report is used in conjunction with the impact and policy analysis reports mentioned above.

Your review and comments on these reports are welcome. Such comments will help us to improve the usefulness of the products produced by our Integrated Assessment Program.

Steven R. Reznek

Acting Deputy Assistant Administrator
for Energy, Minerals and Industry

PREFACE

This Energy Resource Development System (ERDS) report has been prepared as part of "A Technology Assessment of Western Energy Resource Development" being conducted by an interdisciplinary research team from the Science and Public Policy Program (S&PP) of the University of Oklahoma for the Office of Energy, Minerals and Industry (OEMI), Office of Research and Development, U.S. Environmental Protection Agency (EPA). This study is one of several conducted under the Integrated Assessment Program established by OEMI in 1975. Recommended by an interagency task force, the purpose of the Program is to identify economically, environmentally, and socially acceptable energy development alternatives. The overall purposes of this particular study were to identify and analyze a broad range of consequences of energy resource development in the western U.S. and to evaluate and compare alternative courses of action for dealing with the problems and issues either raised or likely to be raised by development of these resources.

The Project Director was Irvin L.(Jack) White, Assistant Director of S&PP and Professor of Political Science at the University of Oklahoma. White is now Special Assistant to Dr. Stephen J. Gage, EPA's Assistant Administrator for Research and Development. R. Leon Leonard, now a senior scientist with Radian Corporation in Austin, Texas, was a Co-Director of the research team, Associate Professor of Aeronautical, Mechanical, and Nuclear Engineering and a Research Fellow in S&PP at the University of Oklahoma. Leonard was responsible for editing and managing the production of this report. EPA Project Officer was Steven E. Plotkin, Office of Energy, Minerals and Industry, Office of Research and Development. Plotkin is now with the Office of Technology Assessment. Other S&PP team members are: Michael A. Chartock, Assistant Professor of Zoology and Research Fellow in S&PP and the other Co-Director of the team; Steven C. Ballard, Assistant Professor of Political Science and Research Fellow in S&PP; Edward J. Malecki, Assistant Professor of Geography and Research Fellow in S&PP; Edward B. Rappaport, Visiting Assistant Professor of Economics and Research Fellow in S&PP; Frank J. Calzonetti, Research Associate (Geography) in S&PP; Timothy A. Hall, Research Associate (Political Science); Gary D. Miller, Graduate Research Assistant (Civil Engineering and Environmental Sciences); and Mark S. Eckert, Graduate Research Assistant (Geography).

Chapters 3-7 were prepared by the Radian Corporation, Austin, Texas, under subcontract to the University of Oklahoma. In each of these chapters, Radian is primarily responsible for the description of the resource base and the technologies and S&PP is primarily responsible for the description of laws and regulations. The Program Manager at Radian was C. Patrick Bartosh. Clinton E. Burklin was responsible for preparation of these five chapters. Other contributors at Radian were: William R. Hearn, Gary D. Jones, William J. Moltz, and Patrick J. Murin.

Additional assistance in the preparation of the ERDS report was provided by Martha W. Gilliland, Executive Director, Energy Policies Studies, Inc., El Paso, Texas; Rodney K. Freed, Attorney, Shawnee, Oklahoma; and Robert W. Rycroft, Assistant Professor of Political Science, University of Denver, Denver, Colorado.

ABSTRACT

This report describes the technologies likely to be used for development of coal, oil shale, uranium, oil, natural gas, and geothermal resources in eight western states (Arizona, Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming). It is part of a three-year "Technology Assessment of Western Energy Resource Development." The study examines the development of these energy resources in the eight states from the present to the year 2000. Other reports describe the analytic structure and conduct of the study, the impacts likely to result when these resources are developed, and analyze policy problems and issues likely to result from that development. The report is published in six volumes. Volume 1 describes the study, the technological activities such as exploration, extraction, and conversion for developing the resource, and laws and regulations which affect the development of more than one of the six resources considered in the study. The remaining five volumes are resource specific: Volume 2, Coal; Volume 3, Oil Shale; Volume 4, Uranium; Volume 5, Oil and Natural Gas; and Volume 6, Geothermal. Each of these volumes provides information on input materials and labor requirements, outputs, residuals, energy requirements, economic costs, and resource specific state and federal laws and regulations.

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CONVERSION FACTORS
ENGLISH UNITS/METRIC UNITS

To Convert From	To	Multiply By
acre	m^2	4046.9
acre-ft/year	gpm	0.6200
acre-ft/year	m^3/yr	1233.5
Btu	joules	1054.4
Btu/hr	watts	0.2931
ft	m	0.3048
gpm	m^3/min	0.003785
hp	watts	745.7
lb	kg	0.4536
psi	pascal	6894.8
ton	kg	907.18

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CHAPTER 3

THE COAL RESOURCE DEVELOPMENT SYSTEM

3.1 INTRODUCTION

This document is one of several reports issued in support of a "Technology Assessment of Western Energy Resource Development," a project jointly conducted by the Science and Public Policy Program of the University of Oklahoma and the Radian Corporation of Austin, Texas. The project is funded by the Office of Energy, Minerals, and Industry, Office of Research and Development, Environmental Protection Agency under Contract 68-01-1916. This document is issued as Chapter 3 of the "Energy Resource Development System" (ERDS) report. For each of six Western energy sources, the ERDS report describes the energy resource base, the technologies used to develop and utilize the resource, the inputs and outputs for each development technology, and the laws and regulations applying to the deployment and operation of each technology. Resources described in the ERDS report are: coal, oil shale, uranium, oil, natural gas, and geothermal energy.

This chapter describes the technologies, inputs, outputs, laws, and regulations associated with the development of coal resources. The chapter comprises eight major sections which begin with a general description of the coal resource.

Section 3.2 then presents a summary of the input requirements and outputs identified in this study as resulting from the development and utilization of the Western coal resouce.

Section 3.3, Coal Resources, describes the characteristics of the Western coal resource. Among the physical characteristics this section includes coal type, rank, quality and general composition of western coals. This section also reviews the location of western coal reserves, their recoverability, and their ownership.

Section 3.4 is a regional overview of the number, size, and types of coal mining operations currently conducted in each of the eight western states of this study.

The remaining sections describe the development of the coal resource as a basic sequence of activities. These activities include exploration, mining, benificiation, and conversion. For each activity, technological alternatives are discussed which represent potential development options, (e.g. coal can be mined underground, in open pits, or by strip mining). The discussion of each activity includes the input requirements, the outputs, and the social control associated with or affecting the development activity. Input requirements include: manpower, materials and equipment, economics, water, land, and ancillary energy. The outputs include the residuals from the activity that may pose environmental hazards such as: air emissions, water effluents, solid wastes, noise pollution, occupational health and safety hazards, and odors. Social controls comprise the laws and regulations, on both the local and national level, governing the development of coal resources.

Section 3.5 discusses the technologies, inputs, outputs, and social controls associated with coal exploration activities. Section 3.5 discusses the same items for the mining of coal including underground and surface mining technologies. Section 3.7 discusses coal beneficiation technologies and Section 3.8 discusses coal conversion technologies including gasification, liquefaction, and electrical generation.

TABLE 3-1. SUMMARY OF IMPACTS ASSOCIATED WITH THE EXPLORATION OF A 30,000 TON PER DAY COAL MINE IN WESTERN U.S.

Inputs	
Manpower	
• geological activities	15.5 man-years
• drilling activities	1.5 man-years
Materials and Equipment	
• vehicles	supplied by contractor
• drilling rigs	
• well logging	
Economics[a]	
• geological activities	$600,000/mine
• drilling activities	$200,000/mine
Water	negligible
Land	temporary and negligible
Ancillary Energy	minor
Outputs	
Air Emissions	minor
Water Effluents	5 acre-ft/mine (6170 m^3/mine)
Solid Wastes	minor
Noise	temporary
Occupational Health and Safety	negligible

[a] 1977 dollars

3.2 SUMMARY

The input requirements and outputs associated with each phase of the coal resource development system are summarized in Tables 3-1 through 3-8. The input requirements include manpower, materials and equipment, economics, water, land, and ancillary energy. The outputs include air, water, and solid waste emissions, noise, odor, and occupational safety and health.

These tables present typical values for a given design basis. The input requirements and outputs will vary significantly with the mode and size of operation, location, specific resource quality, and choice of technology option. The design basis and assumptions applied to develop these tables are described in detail in their respective section of the text.

TABLE 3-2. SUMMARY OF IMPACTS ASSOCIATED WITH 12 MM TPY SURFACE MINE AT NAVAJO

Inputs	
Manpower	
• construction	832 man-years
• operating	552 men
Materials and Equipment	
• stripping shovels (140 cu yd)	3
• cement	62,800 tons (57 Mkg)
• structured steel	940 tons (0.85 Mkg)
• draglines	10,400 tons (9.4 Mkg)
Economics[a]	
• capital cost (estimated)	$104 million
• annual operating cost (estimated)	$ 46 million
Water (reclamation)	4,000 acre-ft/yr (9.4 m^3/min)
Land	20,000 acres (30 yr total) (80.9 Mm^2) 240 acres (at a time) (0.97 Mm^2)
Ancillary Energy	
• electricity	55 x 10^6 kwhr/yr (59 TJ/yr)
• diesel fuel	1.8 x 10^6 gal/yr (0.013 m^3/min)
Outputs	
Air Emissions	
• hydrocarbons	8 lb/hr (3.6 kg/hr)
• particulates	1700 lb/hr (773 kg/hr)
• SO_2	8 lb/hr (3.6 kg/hr)
• NO_x	100 lb/hr (45 kg/hr)
• CO	23 lb/hr (10 kg/hr)
• CO_2	5500 lb/hr (2500 kg/hr)
Water Effluents	recycled
Solid Wastes	returned to mine
Noise Pollution	insignificant
Occupational Health and Safety	
• deaths	0.6 deaths/yr
• injuries	19 injuries/yr
• lost man-days	1300 man-days/yr

[a] 1974 dollars

TABLE 3-3. SUMMARY OF IMPACTS ASSOCIATED WITH A 12 MM TPY UNDERGROUND COAL MINE AT KAIPAROWITS

Inputs	
Manpower	
• construction	2,330 man-years
• operating	2,384 men
Materials and Equipment	
• continuous miners	64
• loading machines	64
• ready mixed concrete	92,000 tons (83.5 Mkg)
• structural steel	6,000 tons (5.4 Mkg)
• reinforcing bars	6,800 tons (6.2 Mkg)
• piping	4,600 tons (4.2 Mkg)
Economics[a]	
• capital costs	$308 million
• operating costs	$100 million
Water	None
Land	
• at any given time	2,750 acres (11.1 Mm^2)
• 30 year total	36,000 acres (145.7 Mm^2)
Ancillary Energy	3.5×10^{12} Btu/yr (3.7 PJ/yr)
Outputs	
Air Emissions	
• particulates	0.35 ton/day (317 kg/day)
• hydrocarbons	144 ton/day (131 Kkg/day)
Water Effluents	highly site dependent
Solid Wastes	78 tons/day
Noise	insignificant
Occupational Health and Safety	
• fatalities	7.2 deaths/yr
• injuries	370 injuries/yr
• lost man-days	210,000 man-days

[a] 1974 dollars

TABLE 3-4. SUMMARY OF IMPACTS ASSOCIATED WITH A 25,000 TPD COAL BENEFICIATION PLANT

Inputs	
Manpower	
• construction	258 man-years
• operating	22 men
Materials and Equipment	Table 3-58
Economics[a]	
• capital cost	\$36.5 million
• operating cost	\$ 2.8 million/yr
Water	1400 gpm (5 m^3/min)
Land	90 acres (364 Km^2)
Ancillary Energy	1.7 x 10^9 Btu/day (0.65 PJ/yr)
Outputs	
Air Emissions	7 lb/hr (3.2 kg/hr)
Water Effluents	none
Solid Wastes	8,000 ton/day (7 Mkg/day)
Noise Pollution	negligible
Occupational Health and Safety	
• deaths	0.56 deaths/yr
• injuries	11 injuries/yr
• man-days lost	4,900 man-days/yr

[a] 1974 dollars

TABLE 3-5. SUMMARY OF IMPACTS ASSOCIATED WITH A 250 MMscfd LURGI COAL GASIFICATION PLANT AT COLSTRIP, MONTANA

Input Requirements	
Manpower	
• construction	10,781 man-years
• operating	589 men
Materials and Equipment	
• structural steel	14,000 tons (12.7 Mkg)
• piping	58,000 tons (52.6 Mkg)
• ready mixed concrete	180,000 tons (163.3 Mkg)
Economics[a]	
• capital costs	$750 million
• operating costs	$9.8 million
Water	9,263 acre-ft/yr (21.7 m^3/min)
Land	800 acres (3.2 Mm^2)
Ancillary Energy	none
Outputs	
Air Emissions	
• particulates	negligible
• SO_2	516 lb/hr (234 kg/hr)
• NO_x	495 lb/hr (225 kg/hr)
• HC	953 lb/hr (433 kg/hr)
• CO	negligible
Water Effluent (plant)	
• to ash ponds	310 gpm (1.1 m^3/min)
• to evaporation ponds	820 gpm (3.1 m^3/min)
Solid Wastes	
• ash	225,000 lb/hr (102 Kkg/hr)
• water treatment sludge	500 lb/hr (227 kg/hr)
• spent catalyst	intermittent
Noise Pollution	negligible
Occupational Health and Safety	
• fatalities	0.45 deaths/yr
• accidents	15 injuries/yr
• man-days lost	4,200 man-days yr

[a] Third-quarter 1974 dollars

TABLE 3-6. SUMMARY OF IMPACTS ASSOCIATED WITH A 250 MMscfd SYNTHANE COAL GASIFICATION PLANT AT COLSTRIP, MONTANA

Input Requirements	
Manpower	
• construction	10,781 man-years
• operating	689 men
Materials and Equipment	
• structural steel	14,000 tons (12.7 Mkg)
• piping	58,000 tons (52.6 Mkg)
• ready mixed concrete	180,000 tons (163.3 Mkg)
Economics[a]	
• capital costs	$750 million
• operating costs	$9.8 million
Water	29,036 acre-ft/yr (68 m^3/min)
Land	800 acres (3.2 Mm^2)
Ancillary Energy	none
Outputs	
Air Emissions	
• particulates	8 lb/hr (3.6 kg/hr)
• SO_2	3524 lb/hr (1602 kg/hr)
• NO_x	5052 lb/hr (2296 kg/hr)
• HC	1047 lb/hr (476 kg/hr)
• CO	176 lb/hr (80 kg/hr)
Water Effluent (plant)	
• to ash ponds	310 gpm (1.1 m^3/min)
• to evaporation ponds	820 gpm (3.1 m^3/min)
Solid Wastes	
• ash	180,000 lb/hr (82 Kkg/hr)
• limestone sludge	110,000 lb/hr (50 Kkg/hr)
• spent catalyst	intermittent
Noise Pollution	negligible
Occupational Health and Safety	
• fatalities	0.45 deaths/yr
• accidents	15 injuries/yr
• man-days lost	4,200 man-days/yr

[a] Third-quarter 1974 dollars

TABLE 3-7. SUMMARY OF IMPACTS ASSOCIATED WITH A 30,000 TPD SRC-II COAL LIQUEFACTION PLANT AT GILLETTE, WYOMING

Input Requirements	
Manpower	
• construction	21,900 man-years
• operating	1,600 men
Materials and Equipment	
• fabricated steel	200,000 tons (181 Mkg)
• concrete	288,000 tons (261 Mkg)
• refined products	50,000 tons (45 Mkg)
Operating Reagents	40 tons/day (36 Kkg/day)
Economics[a]	
• capital costs	\$1.2 - \$1.3 billion
• operating costs (excluding coal costs)	\$219 million/year
Water	
• @ 100% reuse and recycle	4 million gal/day (10.5 m^3/min)
• @ current development plans	17 million gal/day (45 m^3/min)
Land	1800 acres (7.3 Mm^2)
Ancillary Energy	41 MW (1.3 PJ/yr)
Outputs	
Air Emissions	
• particulates	475 lb/hr (216 kg/hr)
• SO_2	248 lb/hr (113 kg/hr)
• total organics	1,067 lb/hr (485 kg/hr)
• CO	126 lb/hr (57 kg/hr)
• NO_x	1,280 lb/hr (582 kg/hr)
• NH_3	12 lb/hr (5 kg/hr)
• CO_2	858,000 lb/hr (390,000 kg/hr)
Water Effluents	negligible
Solid Wastes	2,500 tons/day (2.3 Mkg/day)
Noise	negligible
Odor	trace
Occupational Health and Safety	
• fatalities	0.32 deaths/yr
• injuries	6.2 injuries/yr
• man-days lost	1494 man-days/yr

[a] 1976 dollars

TABLE 3-8. SUMMARY OF IMPACTS ASSOCIATED WITH A 3000 MW POWER PLANT AT GILLETTE, WYOMING

Input Requirements	
Manpower	
• construction phase	9,960 man-years
• operation and maintenance	436 people
Materials and Equipment	
• refined products	72,000 tons (65 Mkg)
• ready mix concrete	456,000 tons (414 Mkg)
• piping	13,000 tons (12 Mkg)
• steel	26,000 tons (24 Mkg)
• steam turbogenerators	4 million hp
• boilers	28 billion Btu/hr
Economics[a]	
• capital cost	$880 million
• operating cost (excluding coal)	$11 million
Water	42,000 acre-ft/year (98 m^3/min)
Land	2,400 acres (9.7 Mm^2)
Ancillary Energy	none
Outputs	
Air Emissions	
• particulates	14 ton/day (12.7 Kkg/day)
• SO$_x$	77 ton/day (69.9 Kkg/day)
• NO$_x$	316 ton/day (286.7 Kkg/day)
• CO	18 ton/day (16.3 Kkg/day)
• HC	5 ton/day (4.5 Kkg/day)
• aldehydes	0.1 ton/day (90 kg/day)
• CO$_2$	76,800 ton/day (70 Mkg/day)
Water Effluents	
• to zero discharge solar evap. ponds	2,096 acre-ft/year (4.9 m^3/min)
Solid Wastes	
• ash	1,745 ton/day (1.58 Mkg/day)
• FGD scrubber sludge	1,488 ton/day (1.35 Mkg/day)
Noise Pollution	minimal
Occupational Safety and Health	
• fatalities	0.77 deaths/yr
• injuries	3.2 injuries/yr
• lost time	1200 man-days/yr

[a] Third-quarter 1974 dollars

3.3 COAL RESOURCES

Coal is a combustible natural solid formed from fossilized plants. It is dark brown to black in color and consists primarily of carbon (more than 50 percent by weight) in the form of numerous complex organic compounds. The composition of coal varies considerably from region to region and within given deposits.

Coal is generally found as a layer in sedimentary rock. These layers, called seams or beds, differ greatly in thickness, depth below the surface, and areal extent. In this section, western coal resources are described in terms of quantity, characteristics, location, and ownership.

3.3.1 Background

Although native Americans have apparently used western coal for centuries, the first recorded coal production in the West was in Colorado in 1864.[1] By then, coal was already becoming the principal energy source for the entire U.S., a position which it maintained from the 1880's until shortly after World War II.[2] The high point for coal came in 1910, when it supplied approximately 75 percent of the total U.S. energy demand. From that time until 1972, coal supplied a decreasing percentage of U.S. energy; and in 1975 it supplied only 18 percent of total

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[1] Neilson, George F., ed. 1974 Keystone Coal Industry Manual. New York: McGraw-Hill Mining Publications, 1974, p. 535.

[2] U.S. Congress, Senate Committee on Interior and Insular Affairs. A National Fuels and Energy Policy Study, Hearings, 92d Cong., 1st sess., October 20, 1971 (pp. 94-102, reprinted from Scientific American, Vol. 225, September 1971).

U.S. consumption.[1] During 1975, coal consumption and production increased slightly. Given a national energy policy which emphasizes decreased dependence on external sources, coal production is expected to increase even further. Some forecasts now suggest that western coal production may more than double by 1985.[2]

3.3.2 Total National Resource Endowment

The U.S. Geological Survey (USGS) estimates the total remaining coal resources of the U.S. to be more than three trillion tons;[3] however, as indicated in Table 3-9, the proportion of this estimate, classified as identified and recoverable, is substantially less than the total. In fact, only about 195 billion tons are classified as reserves, meaning they are (1) known in location, quantity, and quality from geologic evidence supported by engineering measurements, and (2) economically recoverable based upon currently available technologies, and current market value.

Almost 1.2 trillion tons of identified coal resources cannot be economically mined at present, and an additional 1.6

---

[1] Enzer, Hermann, Walter Dupree, and Stanley Miller. Energy Perspectives: A Presentation of Major Energy and Energy-Related Data. Washington: U.S. Dept. of the Interior, 1975, p. 36.

[2] U.S., Federal Energy Administration. National Energy Outlook. Washington: FEA, 1976, pp. 200-203.

[3] The estimates are 2.9 trillion tons within 3,000 feet and 3.2 trillion tons within 6,000 feet of the surface. All estimates are in short (2,000-pound) tons.

TABLE 3-9. COAL RESOURCES OF THE U.S.[a] (Billions of Tons)

Feasibility of Recovery	Knowledge of Resource		
	Discovered	Undiscovered Resources[b]	
	0-3,000 feet overburden	0-3,000 feet overburden	3,000-6,000 feet overburden
Recoverable[c]	100[d] 95[e]	0	0
Submarginal[f]	1,285[g]	1,300	340

[a] Reliability of estimates decreases downward and to the right.

[b] Unspecified bodies of mineral-bearing material surmised to exist on the basis of broad geologic knowledge and theory.

[c] Resources which are both identified and recoverable are termed "reserves"

[d] Coal in beds 42 inches or more thick for bituminous coal and anthracite and 10 feet or more thick for subbituminous coal and lignite; over burden not more than 1,000 feet.

[e] Additional coal recoverable in beds 28 to 42 inches thick for bituminous coal and anthracite and 3 to 5 feet thick for subbituminous coal and lignite; overburden not more than 1,000 feet.

[f] Resources which are technically possible but not economic to mine; a substantially higher price (more than 1.5 times the price at the time of the estimate) or a major cost-reducing advance in technology would be required for these resources to become reserves.

[g] Additional coal recoverable in beds at least 14 inches thick for bituminous coal and anthracite and 2-1/2 feet thick for subbituminous coal and lignite; overburden not more than 3,000 feet.

Sources: Averitt, Paul. "Coal," Donald A. Brobst and Walden P. Pratt, eds. United States Mineral Resources, U.S. Geological Survey Professional Paper 820. Washington: Government Printing Office, 1973, pp. 133-142.

Theobald, P. K., S. P. Schweinfurth, and D. C. Duncan, eds. Energy Resources of the United States, U.S. Geological Survey Circular 650. Washington: Government Printing Office, 1972, p. 3.

trillion tons have not actually been identified but are surmised to exist on the basis of broad geologic knowledge and theory.

Assuming an average heating value of 10,000 Btu's per pound, U.S. coal resources have an energy value equivalent to 850 times the total U.S. energy consumption in 1970.[1] The 195 billion tons of coal "reserves" are equivalent to 55 times the total U.S. energy consumption for that year.

U.S. coal resources account for approximately 32 percent of world coal resources.[2] The Sino-Soviet Bloc possesses a very large share of the remaining 68 percent.

3.3.3 Characteristics of the Resources

Coals are classified on the basis of specific compositional characteristics such as carbon content, heating value, and impurities. Anthracite and bituminous coals are primarily ranked on the basis of fixed carbon content (Figure 3-1).[3] Subbituminous coals and lignite, which contain less fixed carbon, are ranked on the basis of heating value (Figure 3-2). As indicated in Table 3-10, approximately 70 percent of all U.S. coal is bituminous or subbituminous, while only about one percent is anthracite.

In addition to being ranked, coals are graded on the basis of the impurities that they contain. Certain impurities

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[1] Total U.S. energy consumption in 1970 was 69 x 10^{15} Btu's.

[2] Averitt, Paul. "Coal," in Donald A. Brobst and Walden P. Pratt, eds. United States Mineral Resources, U.S. Geological Survey Provessional Paper 820. Washington: Government Printing Office, 1973, pp. 133-142.

[3] Fixed carbon is the solid, nonvolatile portion of coal that is combustible. Rank is one method of categorizing the degree of chemical transformation from ancient plant deposits.

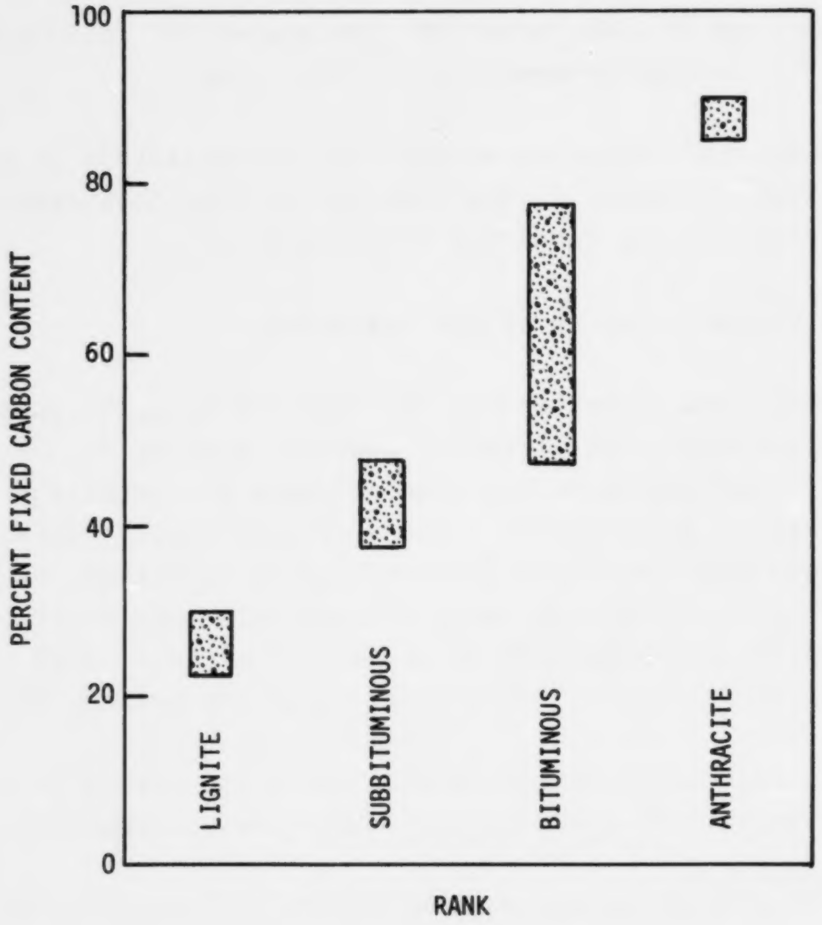

Figure 3-1. Range in Fixed Carbon Contents of Major Coal Ranks.

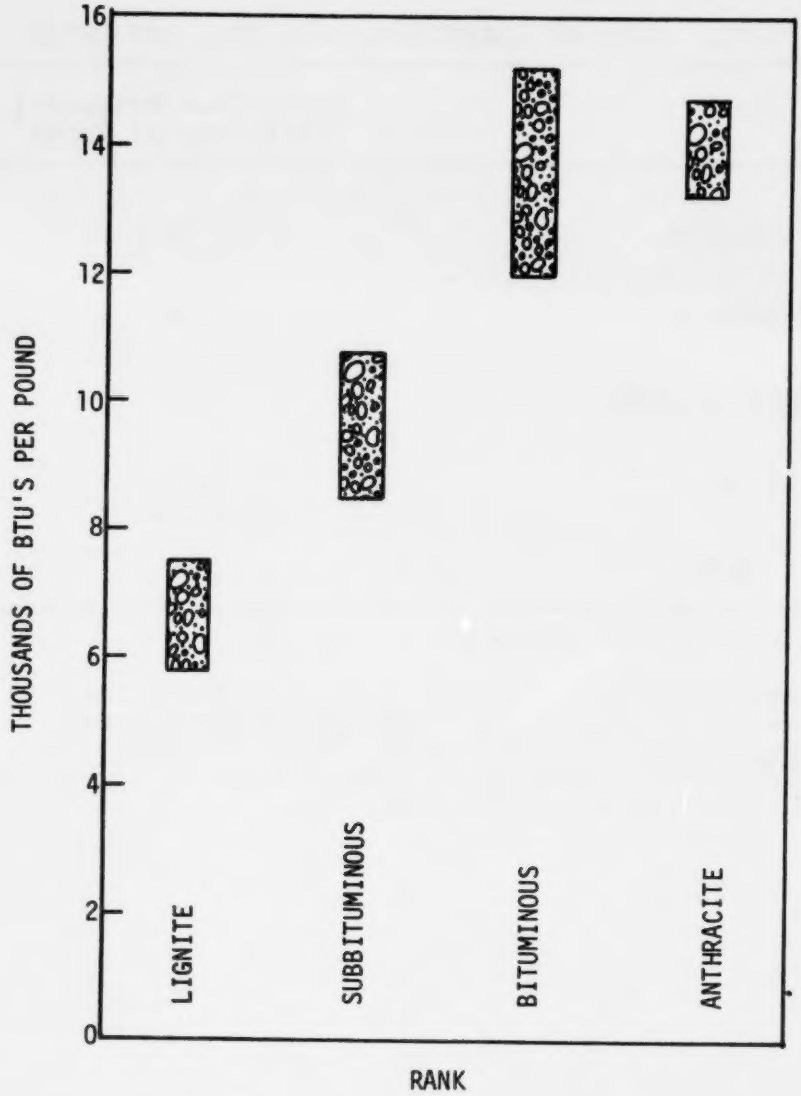

Figure 3-2. Range in Heat Contents of Major Coal Ranks.

TABLE 3-10. RANK OF IDENTIFIED U.S. COAL RESOURCES

Rank	Identified Resources (Billions of Tons)[a]
Anthracite	21
Bituminous	686
Subbituminous	424
Lignite	449
TOTAL	1,580

[a] In short tons (2,000 pounds).

Source: Averitt, Paul. "Coal," Donald A. Brobst and Walden P. Pratt, eds. United States Mineral Resources, U.S. Geological Survey Professional Paper 820. Washington: Government Printing Office, 1973, pp. 133-142.

(including moisture, ash, and sulfur) present problems when coal is processed and utilized. Moisture ranges from one percent in some anthracites to more than 40 percent in some lignites.[1]

The ash content of coal (the amount of noncombustible inorganic materials the coal contains) varies considerably even within a single seam, making proportional generalization difficult. For example, in a 1942 study of 642 typical U.S. coals, investigators found that ash content ranged from 2.5 to 32.6 percent.[2]

One impurity that causes great difficulty is sulfur. The sulfur content of U.S. coals ranges from 0.2 to 7.0 percent, varying considerably between geographic regions. Most of the low-sulfur coal (coal with a sulfur content of one percent or less) is located in the western U.S.[3] On an equivalent Btu basis, however, the contrast in sulfur contents between western and eastern coals is often diminished because western coals generally have a lower heating value then do eastern coals. A comparison of sulfur content and heating value for various coals is shown in Table 3-11.

3.3.4 Location of the Resources

Coal occurs in many parts of the U.S.: bituminous in Appalachia and the drainage basin of the Mississippi River; a

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[1] U.S., Department of the Interior, Bureau of Land Management. Draft Environmental Impact Statement: Proposed Federal Coal Leasing Program, 2 vols. Washington: Government Printing Office, 1974.

[2] Ibid.

[3] Ibid., Vol. I, p. I-57.

TABLE 3-11. COMPARISON OF EASTERN AND WESTERN COAL QUALITIES

	Heat Content Btu/lb	Sulfur Content	Maximum Allowable Sulfur Content Under New Source Performance Standards	Moisture Content[a]	Amount Mined to Obtain 1×10^6 Btu's
A. "Typical" Eastern Coals					
1. Anthracite (Pennsylvania)	14,000	0.7% or less	1%	5%	71 lbs
2. Bituminous (Appalachian, Central States)	13,000	less than 0.7% to over 4%	0.78%	5%	77 lbs
B. "Typical" Western Coals					
1. Bituminous (deep) (Colorado, Utah, Wyoming, New Mexico)	13,000	less than 0.7% to 1.0%, with minor quantities up to and over 4%	0.78%	5%	77 lbs
2. Sub-Bituminous (Montana, Wyoming, Colorado, New Mexico)	8,000 to 9,500	less than 0.7% to 2%	0.48% to 0.57%	25%	125 lbs to 105 lbs
3. Lignite (Montana, North and South Dakota)	6,000	less than 0.7% to 1.5%	0.36%	40%	167 lbs

[a] Moisture content is a function primarily of local and regional hydrology; sub-bituminous and lignite deposits in the west typically function as aquifers.

Source for Chart: Environmental Policy Center. Facts About Coal in the United States. Washington: Environmental Policy Center, 1974 Data, USGS and U.S. Bureau of Mines.

mixture of ranks in the Northern Great Plains and Rocky Mountains; and scattered deposits elsewhere (Figure 3-3). However, almost 90 percent of all coal resources in the contiguous 48 states are located in four USGS coal provinces: the Eastern, Interior, Northern Great Plains, and Rocky Mountain (Table 3-12). The provinces[1] located in the western states are described in the following regional overview; Section 3.4.

3.3.5 Recoverability of the Resources

Two of the most important factors in the recoverability of coal are bed depth and seam thickness. Although both are major economic factors, bed depth is often the more important because of the lower cost and relatively greater safety of surface mining. In 1965, the average depth of coal being mined from the surface was 55 feet and the average seam thickness was 5.2 feet, giving a ratio of overburden-to-seam thickness of roughly 10:1.[2] This ratio has been increasing as mining technologies have advanced, and a 30:1 ratio is now estimated to be reasonable for the mid-1970's.[3] Whether or not a 30:1 ratio is generally reached,

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[1] A province, the largest unit used by USGS to define the areal extent of coal resources, is made up of regions of the basis of similarity in the physical features of coal fields, coal quality, and contiguity. Regions are made up of fields which are made up of districts. A field is a recognizable single coal-bearing territory; a district is an identifiable center of coal mining operations. These four terms provide a convenient means for aggregating and disaggregating data on coal resources and production.

[2] Young, W. H. Thickness of Bituminous Coal and Lignite Seams Mined in 1965, Bureau of Mines Information Circular 8345. Washington: Government Printing Office, 1967, p. 18.

[3] Averitt, Paul. Stripping-Coal Resources of the United States--January 1, 1970, U.S. Geological Survey Bulletin 1322. Washington: Government Printing Office, 1970. Note: Selected thin seams of coal for metallurgical use are presently mined at a 40:1 ratio in Oklahoma (Johnson, 1974).

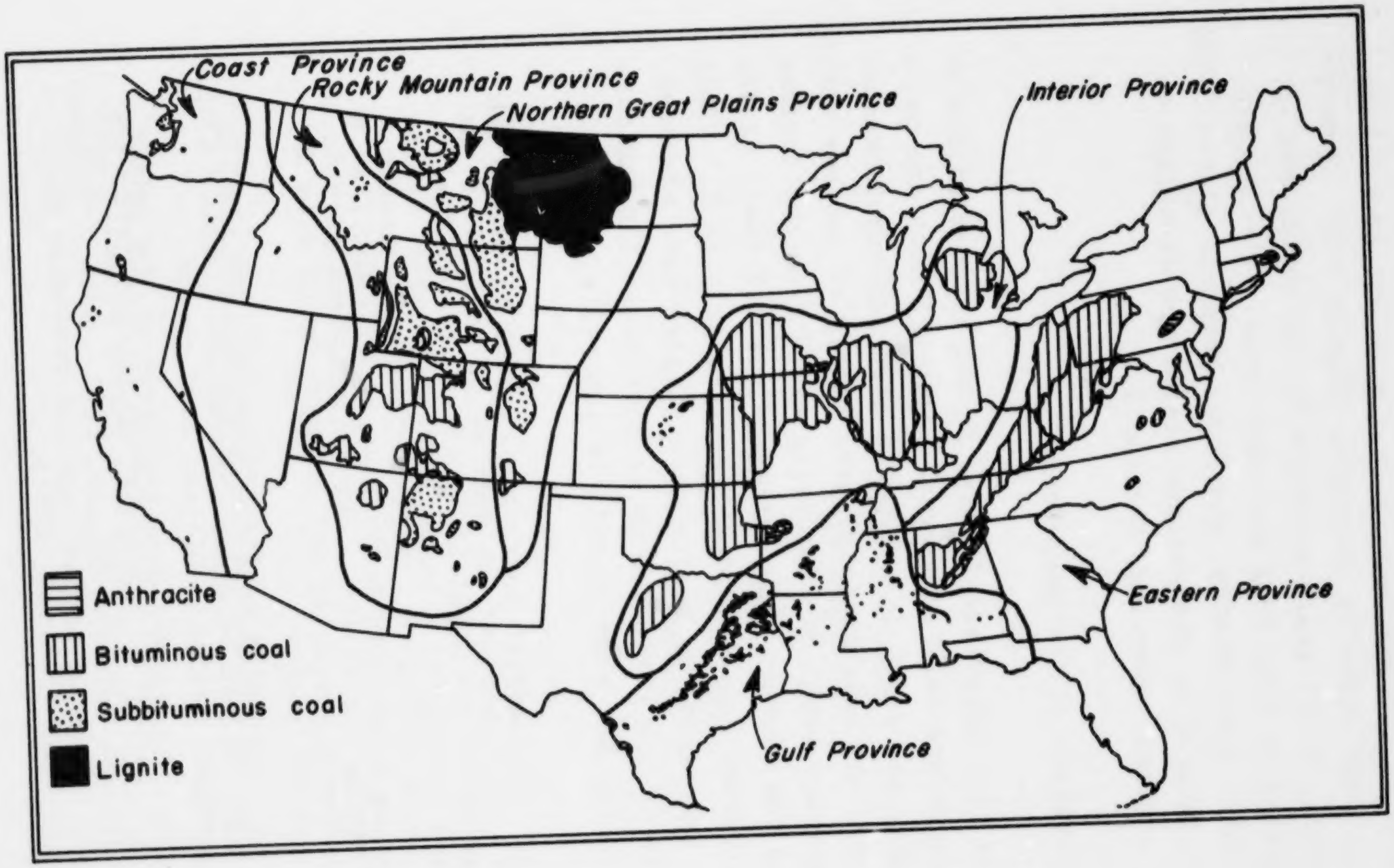
Coast Province
Rocky Mountain Province
Northern Great Plains Province
Interior Province
Eastern Province
Gulf Province
Anthracite
Bituminous coal
Subbituminous coal
Lignite

Figure 3-3. Distribution of United States Coal Resources.

Source: U.S., Department of the Interior, Bureau of Land Management. Draft Environmental Impact Statement: Proposed Federal Coal Leasing Program, 2 vols. Washington: Government Printing Office. 1974.

TABLE 3-12. COAL RESOURCES IN U.S. GEOLOGICAL SURVEY PROVINCES[a] (Billions of Tons)

Province	Identified	Undiscovered	Total
Eastern	276	45	321
Interior	277	259	536
Northern Great Plains	695	763	1,458
Rocky Mountains	187	395	582
Other	146	181	327

[a] Because available estimates are by state and USGS Provinces cross state boundaries, the figures for these provinces are only approximate.

Source: Averitt, Paul. "Coal," Donald A. Brobst and Walden P. Pratt, eds. United States Mineral Resources, U.S. Geological Survey Professional Paper 820. Washington: Government Printing Office, 1973, pp. 133-142.

approximately 45 billion tons of coal are now considered economically recoverable using available surface mining technologies.[1]

3.3.6 Ownership of Resources

The development of a coal, regardless of its compositional characteristics, depth, and seam thickness, depends in large part on the ownership of the lands and/or mineral rights. The federal government owns approximately 48 percent of all coal lands located in Alaska, Colorado, Montana, North Dakota, Oklahoma, Utah, and Wyoming.[2] Although overall data are not available, apparently the federal government owns less than four percent of the coal lands in each of the other states. In any case, the major coal lands in the eastern and midwestern U.S. are privately owned.

Most U.S. coal is mined from privately-owned lands. In 1971, only about three percent of the coal produced in the U.S. was mined from lands owned by the federal government or Indians.[3] In part, this is because only about 800,000 acres of federal coal lands (one percent of the more than 85 million acres of coal lands that are federally owned) have been leased for development. This pattern will change as more mines are opened in the Northern Great Plains and Rocky Mountain provinces.

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[1] U.S., Department of the Interior, Bureau of Mines. Strippable Reserves of Bituminous Coal and Lignite in the United States, Information Circular 8351. Washington: Government Printing Office, 1974, Vol. 1, p. V-208.

[2] U.S., Department of the Interior, Bureau of Land Management, Draft Environmental Impact Statement: Proposed Federal Coal Leasing Program, 2 vols. Washington: Government Printing Office, 1974, 2 vols. Washington: Government Printing Office, 1974, Vol. 1, p. V-208.

[3] *Ibid.*, Vol. I, p. I-64.

Reserves presently committed under lease and preference right lease application are not well defined. Surface and mineral ownership for the Northern Great Plains Province is shown in Table 3-13. The issue of surface and mineral ownership and how it affects coal leasing and development is discussed in the social controls, leasing section following.

TABLE 3-13. SURFACE AND MINERAL OWNERSHIP OF STUDY AREA BY OWNER AND STATE (In Percent of Total)

	Owner					
State	Type of Ownership	Federal Acres	Indian Acres	County Municipal and Private acres[a]	State Acres	Total Acres Million
Montana	Surface	17.0	8.2	69.0	5.8	34.5
	Mineral	33.0	7.9	53.3	5.8	
North Dakota	Surface	7.3	2.7	87.5	2.5	26.7
	Mineral	20.3	3.8	73.4	2.5	
South Dakota	Surface	5.6	16.6	71.9	5.9	11.7
	Mineral	12.1	18.0	57.0	12.0	
Wyoming	Surface	22.9	0	68.5	8.6	18.6
	Mineral	42.6	0	48.7	8.7	

[a] Included substantial surface and mineral rights held by the Burlington-Northern Railroad.

Source: Northern Great Plains Resources Program. Surface Resources Work Group -- Impact Analysis, Discussion Draft. Denver: Northern Great Plains Resources Program, 1974.

3.4 A REGIONAL OVERVIEW

3.4.1 The Northern Great Plains Province

As illustrated in Figure 3-4, the Northern Great Plains Province, which contains 45 percent of the remaining coal resources in the U.S., is made up of six regions. The two largest regions, Fort Union and Powder River, contain almost 1.5 trillion tons of coal or approximately 50% of total estimated U.S. reserves (Table 3-14), most of which is owned by the federal government. Indian tribes and railroads are also large owners.

Most of the coal within the province is relatively low in rank, lignite in the Fort Union Region and thick deposits of subbituminous in the Powder River Region. Near the edge of the Rocky Mountains, the coal is somewhat higher in rank. The moisture and volatile matter content of both Fort Union and Powder River coals are relatively high and, as indictated by their low rank, both tend to be low in energy value. However, more than 657 billion tons or about 44 percent of the province's coal is low sulfur.

Although seam depth and thickness in the province vary considerably, some beds are quite thick and near enough to the surface to allow surface mining.

Much of the surface area of the province is still covered by native vegetation. However, some parts of the province, particularly the areas along the Missouri River, are farmed intensively.

Water supplies are not abundant, and most of the surface water is found in the Northern Missouri River drainage basin.

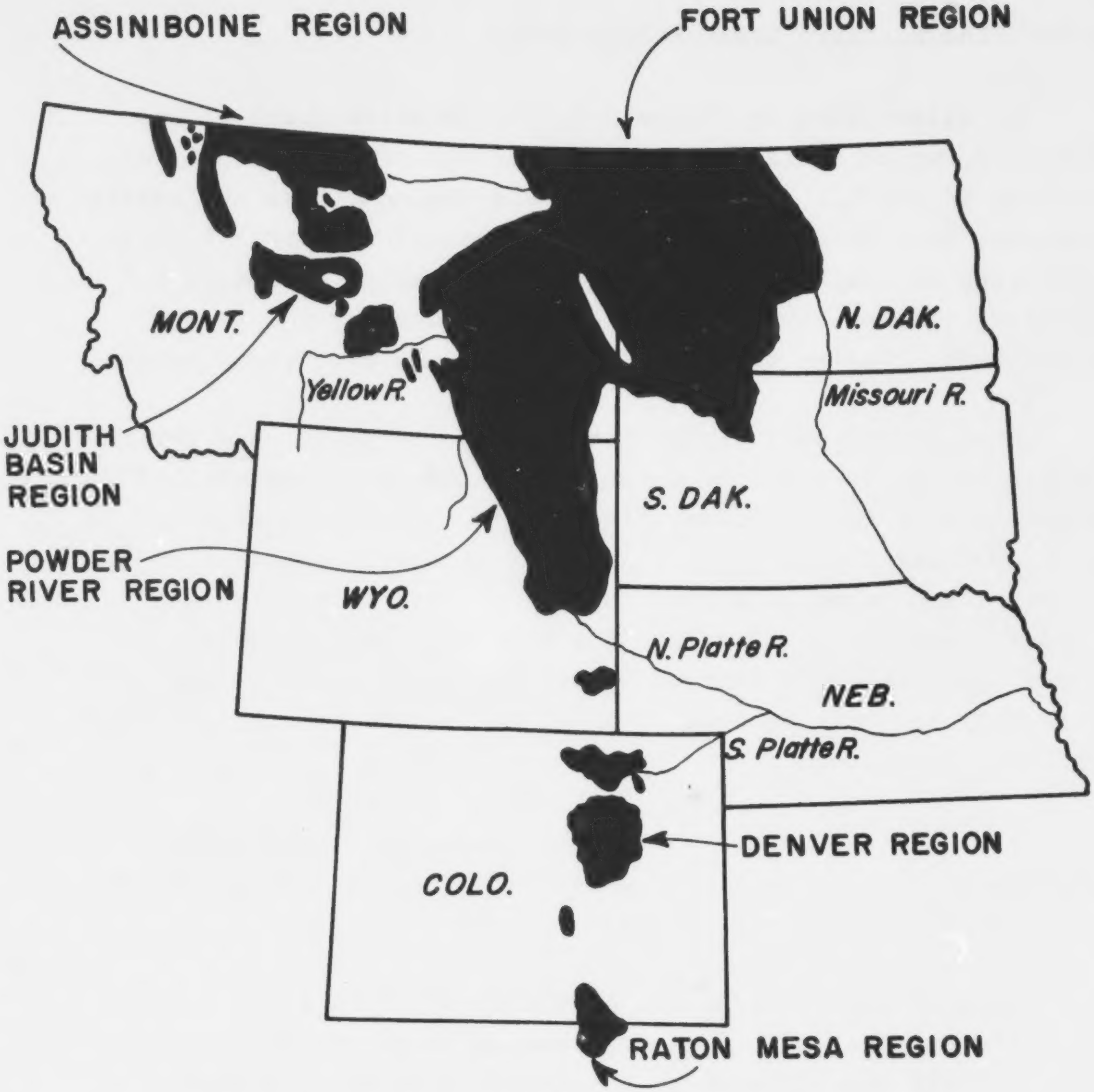
ASSINIBOINE REGION
FORT UNION REGION
MONT.
N. DAK.
Yellow R.
Missouri R.
JUDITH BASIN REGION
S. DAK.
POWDER RIVER REGION
WYO.
N. Platte R.
NEB.
S. Platte R.
DENVER REGION
COLO.
RATON MESA REGION

Figure 3-4. Distribution of Coal in the Northern Great Plains Province.

Source: U.S., Department of the Interior, Bureau of Land Management. Draft Environmental Impact Statement: Proposed Federal Coal Leasing Program, 2 vols. Washington: Government Printing Office. 1974. p. II-132.

TABLE 3-14. COAL RESOURCES IN THE NORTHERN GREAT PLAINS PROVINCE

Depth (feet)	Status	Amount (Billion Tons)
0-1,000	Recoverable	106[a]
0-3,000	Thin bed and identified	589
0-3,000	Undiscovered	663
3,000-6,000	Undiscovered	100
TOTAL		1,458

[a] Does not include mining losses. Coal out-of-the-ground would be approximately 50 percent of this value.

Sources: U.S. Department of the Interior, Bureau of Land Management. Draft Environmental Impact Statement: Proposed Federal Coal Leasing Program, 2 vols. Washington: Government Printing Office, 1974, pp. 1-69.

Averitt, Paul. "Coal," Donald A. Brobst and Walden P. Pratt, eds. United States Mineral Resources, U.S. Geological Survey Professional Paper 820. Washington: Government Printing Office, 1973, p. 137.

Much of this water comes from runoff from the mountains to the west. The average annual runoff for the Northern Great Plains Province ranges from less than 1 inch up to 10 inches.

3.4.2 The Rocky Mountain Province

The largest three of the Rocky Mountain Province's eight regions (Figure 3-5) are the Green River, Uinta, and San Juan River. As shown in Table 3-15, estimated remaining resources in the province are more than 580 billion tons, 187 billion of which have been identified. Resource ownership in the province is largely shared by the federal government, Indian tribes, and railroads.

This province has the greatest variety in ranks and geologic setting of any province in the U.S. Coals of greatest current interest are subbituminous and low-grade bituminous, found mainly in the southern part of the province and in the Green River and Uinta Regions. Moisutre content tends to be low and volatile matter content relatively high. Heating values range from 5,000 to more than 14,000 Btu's per pound.[1] Sulfur content is generally low, with almost 90 percent of identified resources having a sulfur content of one percent or less.

The depth and thickness of coal seams in the province vary greatly. A number of thick seams are being surface mined at the present time; other, deeper seams are not.

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[1] U.S., Department of the Interior, Bureau of Land Management. Draft Environmental Impact Statement: Proposed Federal Coal Leasing Program, 2 vols. Washington: Government Printing Office, 1974, Vol. I, p. I-57.

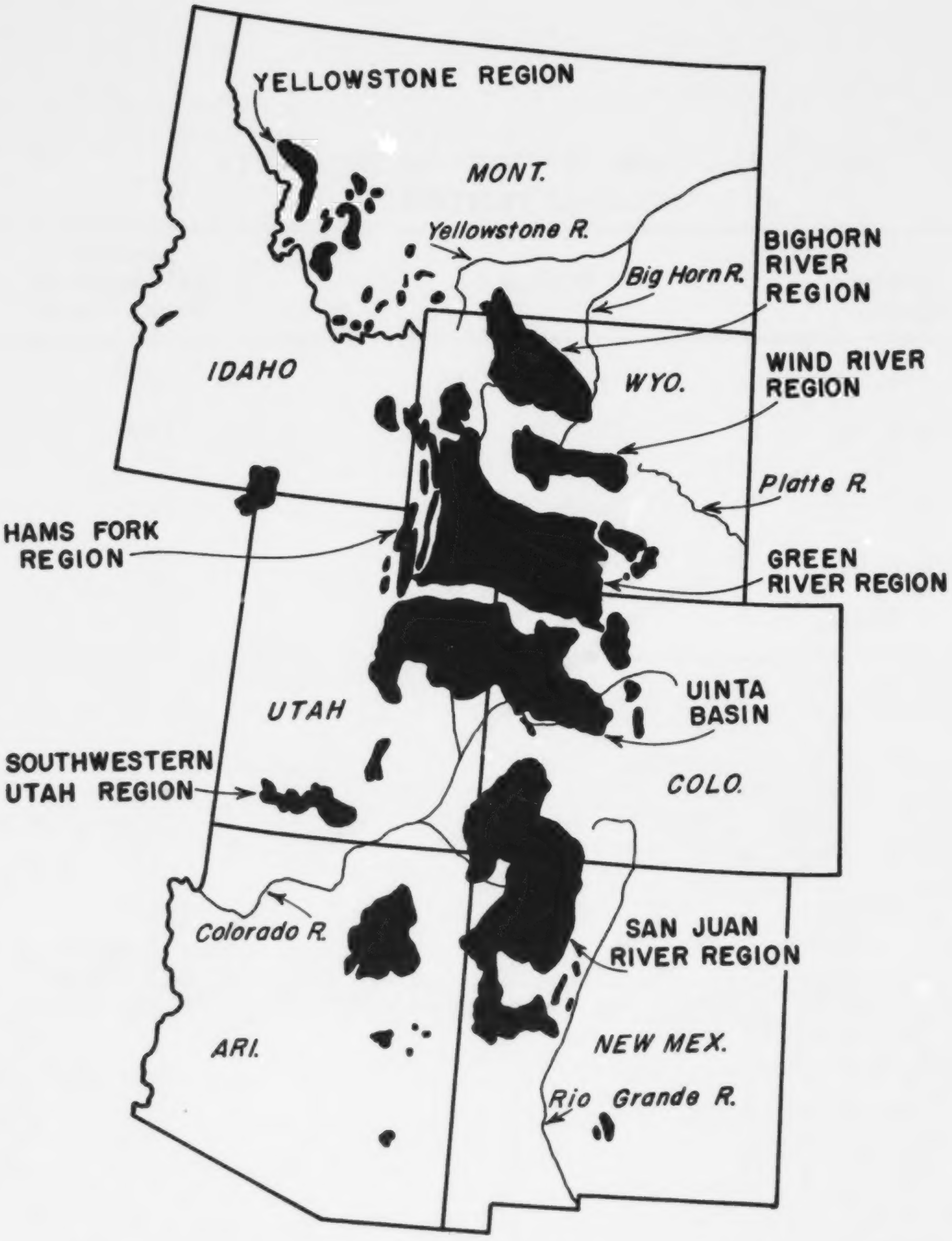
YELLOWSTONE REGION
MONT.
Yellowstone R.
Big Horn R.
BIGHORN RIVER REGION
IDAHO
WYO.
WIND RIVER REGION
Platte R.
HAMS FORK REGION
GREEN RIVER REGION
UINTA BASIN
UTAH
SOUTHWESTERN UTAH REGION
COLO.
Colorado R.
SAN JUAN RIVER REGION
ARI.
NEW MEX.
Rio Grande R.

Figure 3-5. Distribution of Coal in the Rocky Mountain Province.

Source: U.S., Department of the Interior, Bureau of Land Management. Draft Environmental Impact Statement: Proposed Federal Coal Leasing Program, 2 vols. Washington: Government Printing Office. 1974.

TABLE 3-15. COAL RESOURCES IN THE ROCKY MOUNTAIN PROVINCE

Depth (feet)	Status	Amount (Billions of Short Tons)
0-1,000	Recoverable	37[a]
0-3,000	Thin bed and identified	150
0-3,000	Undiscovered	194
3,000-6,000	Undiscovered	201
TOTAL		582

[a] Does not include mining losses. Coal out-of-the-ground would be approximately 50 percent of this value.

Source: U.S. Department of the Interior, Bureau of Land Management. Draft Environmental Impact Statement: Proposed Federal Coal Leasing Program, 2 vols. Washington: Government Printing Office, 1974, p. 1-69.

Averitt, Paul. "Coal," Donald A. Brobst and Walden P. Pratt, eds. United States Mineral Resources, U.S. Geological Survey Professional Paper 820. Washington: Government Printing Office, 1973, p. 137.

Much of the province is still covered by natural vegetation, and grazing is a major land use. Mining, logging, ranching, and farming are other uses.

Except for the high mountains, precipitation averages less than 16 inches a year, and large semidesert areas receive less than eight inches. As a consequence, water is almost universally scarce in the province.

The breakdown by states of the western coal reserve base is given in Table 3-16. The total reserves in the western states differ from that summed from Tables 3-14 and 3-15 because of the omission of the Pacific Province (about one percent of the total in the state of Washington), because the totals in Table 3-16 do not specify the seam thickness and depth of reserves, and because a 100 percent recovery factor was included.

Coal production by state in 1976 was as follows:[1]

ARIZONA - One strip mine at Black Mesa in Navajo County produced 10.2 million short tons (MMst) which was shipped by slurry pipeline.

COLORADO[2] - Twenty-one underground mines, two of which produced more than one-half MMst each, in ten counties produced a total of 4.2 MMst. Thirteen surface mines, three of which produced over one-half MMst, in four

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[1] Neilson, George F., ed. 1977 Keystone Coal Industry Manual. New York, New York. McGraw-Hill Mining Publications, 1977.

[2] Kimball, Dan, EPA Region VIII Coal Mine Report, Denver, Colorado, Environmental Protection Agency, Forthcoming.

TABLE 3-16. WESTERN COAL RESERVES BY STATE[a] (Million Tons)

	Potential Mining Method		
	Underground	Surface	Total
Arizona	0	350	350
Colorado	14,000	870	14,870
Montana	65,165	42,562	107,727
New Mexico	2,136	2,258	4,394
North Dakota		16,003	16,003
South Dakota	0	428	428
Utah	3,780	262	4,042
Wyoming	27,554	23,674	51,228
TOTAL WESTERN STATES	114,082	86,915	200,997
TOTAL U.S.	297,235	136,713	433,948

[a] Includes measured and indicated categories as defined by the USBM and USGS and represents 100 percent of the coal in place.

Source: Dupree, Walter G., Jr. and John S. Corsentino. United States Energy Through the Year 2000, Revised. Washington: Bureau of Mines, 1975, p. 5.

counties produced 7.7 MMst. Total production for Colorado in 1977 was 11.9 MMst. Shipment of this coal was predominantly (78 percent) by rail.

MONTANA[1] - Six strip mines, two of which produced about 10 MMst each and two of which produced over two MMst each, in three counties produced 27 MMst of bituminous coal which was shipped by rail. Two strip mines in two counties produced 320,000 tons of lignite which was also shipped by rail.

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[1] Kimball, Dan, EPA Region VIII Coal Mine Report, Denver, Colorado, Environmental Protection Agency, Forthcoming.

NEW MEXICO - One underground mine which had approximately one MMst production, and five strip mines, one of which produced over six MMst, all of which were confined to three counties produced 9.8 MMst, most of which is used in mine mouth power generation. The remainder is shipped by rail.

NORTH DAKOTA[1] - Twelve strip mines, five of which produced over one MMst, in nine counties produced 12 MMst of lignite, the major portion of which was either used in mine mouth power generation or shipped by rail to nearby South Dakota and Western Minnesota.

SOUTH DAKOTA - No coal production in 1976.

UTAH[2] - Sixteen underground mines, only one of which produced over one MMst, in three counties produced 8.8 MMst, most of which was shipped by rail and some by truck.

WYOMING[3] - Four underground mines in three counties produce .62 MMst. Fifteen strip mines, twelve of which produce over one MMst each, in six counties produce 43.4 MMst of coal. Of that, approximately half is shipped out of state by rail and one-fourth is used instate by generating plants. Total state production is 44.0 MMst.

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[1] Kimball, Dan, EPA Region VIII Coal Mine Report, Denver, Colorado, Environmental Protection Agency, Forthcoming.

[2] *Ibid.*

[3] *Ibid.*

3.4.3 SUMMARY

A number of important points emerge from this brief description of U.S. coal resources. Four major provinces--Rocky Mountain, Northern Great Plains, Interior, and Eastern--contain more than 90 percent of all coal resources in the contiguous 48 states. There are major differences between these provinces in terms of the quantity and quality of their coal, ownership, bed depth, seam thickness, availability of water resources, and competition for surface area usage. Further, these differences will become increasingly important as technologies are developed to make coal a more acceptable, less environmentally threatening source of energy.

The Northern Great Plains and Rocky Mountain Provinces contain approximately 70 percent of the coal resources in the four major provinces and most of the nation's low-sulfur coal. Other characteristics of these two provinces are:

1. Much of the coal likely to be developed in the near future can be surface mined,
2. Competition for surface area usage is relatively low,
3. The federal government controls the majority of the coal lands,
4. The coals are relatively low in energy value per unit weight, and
5. Water resources are not plentiful.

These points should be kept in mind when reading the remaining sections in this chapter.

3.5 EXPLORATION

Coal in the western U.S. occurs in sedimentary rocks that, for the most part, are composed of ancient river and delta deposits. The location and distribution of coal that is shallow enough for conventional surface or underground mining are relatively well known. Consequently, most of the exploration effort involves finding and evaluating known deposits that are economically and environmentally attractive for a specific energy need rather than locating new deposits.

3.5.1 Technologies

An exploration strategy for locating a coal mine site typically consists of four stages. These four stages are outlined in Table 3-17.

Two different but related technologies are used in coal exploration: geologic techniques and drilling. Borehole geophysics are also usually used in conjunction with a drilling program. A team of geologists and support personnel are required to conduct geologic studies, and a drilling crew is necessary to operate equipment during the drilling program.

Geological techniques are used in all steps of the exploration strategy, including outlining and conducting the drilling program. The most important geologic subdiscipline in coal exploration is stratigraphy because western coals are found in sedimentary rocks. Economic geology and structural geology are also essential. The specific geologic methods used are primarily surface and subsurface mapping of geologic parameters that are significant to the occurrence of coal. Examples of useful maps are coal thickness maps, overburden thickness maps, and structural geology maps.

TABLE 3-17. OUTLINE OR REGIONAL AND DETAILED EXPLORATION PROGRAM

Exploration Stages		Search for a New Coal Deposit in Western U.S.A.
Stage 1	Regional Appraisal	O - Geologic Compilation for "marketing area.*
Stage 2	Detailed Reconnaissance	F - Field check of sections containing coal seams.*
		F - Reconnaissance drilling for stratigraphy and coal thickness.
		F - Chemical and calorific check of outcrops or drill samples (not badly burned).
Stage 3	Detailed Surface Investigation of Target Area	F - Field check of sections containing coal seams.
Stage 4	Detailed Three Dimensional Physical Sampling of Target Area	F - Drilling* - Logging
		L - Mineralogical, chemical analyses and physical tests on samples, cores and cuttings.*
		F - Down-hole geophysical surveys.
		O - Reserves computations.*
		O - Preliminary valuation.*
		F - Investigation of water problems and water availability for facilities.*
		F - Investigation of suitability of ground for plant, dump, and town sites.
		F - Punch mine to obtain bulk samples.
		L - Bulk tests.

Legend

O - Office study

F - Field investigation

L - Laboratory tests

* - Activity or method which is indispensable

Two types of drilling methods are most frequently used in coal exploration: standard rotary drilling and coring. When the standard rotary drilling is used, samples are taken from the drill cuttings as the borehole progresses. Coring yields a much better and more complete sample (a nearly complete cylinder of relatively undisturbed rock) from the borehole, but this method is much more expensive. Diamond coring bits are sometimes used in core drilling. A rig capable of routinely drilling holes one thousand feet deep usually requires a crew of three: a driller and two assistants. Borehole geophysical logs for lithological interpretation and correlation purposes are usually run under contract by companies specializing in this field.

For an area in which no previous exploration has occurred, the regional appraisal might begin with drilling on a five-mile spacing, and narrow to a one-mile spacing in areas with good prospects.

3.5.2 Input Requirements

This section presents the input requirements for exploring and characterizing a new coal deposit in the Western United States. An area of 625 square miles will be explored for the proper site to locate a 65-square mile coal mine. A mine this size could produce over 30 thousand tons of coal per day for thirty years. It is assumed that a 25-hole drilling program will be required in the exploration.

3.5.2a Manpower Requirements

Professional geologists and a support staff are required at all stages of the exploration for coal deposits. Table 3-18 presents a gross estimate of the manpower requirements for the various stages of the exploration effort.

TABLE 3-18. ESTIMATED MANPOWER REQUIREMENTS FOR GEOLOGIC TECHNIQUES FOR COAL EXPLORATION

Activity	Geologists (2)	Support Personnel (3)
Review of existing data	2.0 man-years	3.0 man-years
Field work for site evaluations	1.0 man-years	1.5 man-years
Preparation of preliminary report	0.5 man-years	1.0 man-years
Outline and conduct drilling program	1.5 man-years	2.5 man-years
Interpretation of results, final reports, and recommendations	1.0 man-years	1.5 man-years
TOTAL	6.0 man-years	9.5 man-years

Assuming a crew size of three for a 1000-foot capacity drilling rig and a drilling rate of one hole per week, the manpower requirements for the drilling activities are an additional 1.5 man-years.

3.5.2b Materials and Equipment

The materials and equipment required for geologic exploration include office space and supplies, appropriate maps, access to a properly stocked library and well log file, drafting and map-making facilities, and materials for report writing. For the field work and drilling parts of the exploration program, field vehicles and equipment are also required.

Generally, the materials and equipment required for drilling activities will not be provided by those conducting the exploration, but will be provided by a contractor who is commissioned for the drilling. This equipment includes such items as a drill rig, water truck and/or air compressor, drill pipe and bits, and core barrel (if applicable). Facilities and equipment must also be provided for the well-site geologist, including a logging trailer, and sample description and collection material. Borehole geophysical equipment, including a logging truck and appropriate sondes (probes) are usually provided by a contractor specializing in well logging.

3.5.2c Economics

The costs of exploration relate directly to the manpower and the materials and equipment requirements. The manpower requirements of Table 3-18 can be translated into manpower costs by assuming a man-year cost of $50,000 for professional geologists and $30,000 for supporting personnel as follows:

Personnel	Man-Year Cost	Man-Years	Total-Cost
Geologists	$50,000	6.0	$300,000
Support	$30,000	10.0	300,000
			$600,000

Materials and equipment associated with the geological activities are assumed to be available from existing facilities. Their costs will, in any case, be relatively small.

Assuming a man-year cost of about $30,000 each for the three-man crew of a drilling rig, the manpower costs for the drilling program should be about $45,000 for 1.5 man-years. Equipment rental costs should be about $6000 per week for 25 weeks, or about $150,000. Total costs for the drilling portion of the exploration program are expected to be approximately $200,000. An unknown and probably small cost is associated with borehole geophysical logs.

3.5.2d Water Requirements

The water needs for geologic methods are negligible. Drilling by the rotary method may require as much as five acre-feet of water for the projected 25 holes, but this quantity is not large enough to be significant to a large coal mining operation.

3.5.2e Land Requirements

No land is required for the geologic techniques. Some land must be cleared for drill sites during the drilling program, but this area is small and only occupied for about a week.

3.5.2f Ancillary Energy

Small quantities of fuel for field vehicles are required during the field work part of geologic techniques. Larger but still relatively minor amounts of fuel are used to drill exploration holes and to move between drill sites.

3.5.3 Outputs

Only a few minor residuals are associated with exploration activities for locating a new coal mine. Much larger quantities of each of three residuals will be associated with the construction and operation of the coal mine itself.

3.5.3a Air Emissions

Small quantities of motor vehicle exhaust are generated by field vehicles and drilling equipment during exploration. Both gasoline and diesel engines are used on this equipment. There may also be small quantities of dust generated by exploration vehicles traveling on dirt roads.

3.5.3b Water Effluents

Small quantities of water effluent are produced by geologic techniques. As much as five acre-feet of drilling fluid may be generated during rotary drilling operations, but this quantity is relatively small and the surface and subsurface pollution potential is minimal and highly localized. There may also be localized increases in stream turbidity associated with drainage changes caused by access roads and cuttings piles.

Where drill holes traverse multiple aquifers, care must be taken to seal and plug the drill holes to prevent aquifer contamination or depletion through interconnection.

3.5.3c Solid Waste

Very little solid waste is produced during the geologic investigation and the drilling phases of exploration. These solid wastes consist of spent drilling mud and drilling cuttings. The actual volume of these wastes is very small and they can be plowed into the local soil for disposal.

3.5.3d Noise Pollution

Very little noise is generated by the geological activities. However, some local and temporary noise is produced by rig operations during the drilling activities of exploration. In recent years equipment has been developed to reduce and muffle the noise from drilling machinery. This equipment can be used if found necessary.

3.5.3e Occupational Health and Safety

During the field work, work parties are exposed to such hazards as falls, snakebite, and heat prostration. Drilling operations pose larger but nevertheless relatively small hazards to crew personnel. Injury associated with equipment operation is not an infrequent occurrence on drill rigs.

3.5.4 Social Controls

In the following section, federal, Indian and state regulation of exploration are described. The process of obtaining the lands for subsequent mining operations will be described in Section 3.6.3 on coal mining and reclamation social controls. Administrative controls such as the environmental impact statement process have been described in Chapter 2.

3.5.4a Exploration Permits on Federal Land[1]

For both the federal and state governments, the exploration process begins with the issuance of prospecting permit as shown in Figure 3-6.

Application for federal prospecting permits are made to the Secretary of the Interior, usually through the local USGS Office. A description of the exploratory plan, an estimate of the costs, and a timetable for diligent development must accompany the application. Following approval of the plan and preliminary environmental assessment by USGS, USGS has broad discretionary authority to establish terms under which exploration will take place.

The permit is issued for two-year periods and may be extended for periods of two years if the permittee has, with the

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[1] New regulations concerning exploration are being promulgated as a result of the Surface Mining Control and Reclamation Act of 1977, Pub. L. 95-87, 30 USC 1201. These regulations were not final as of the date of publication of this document.

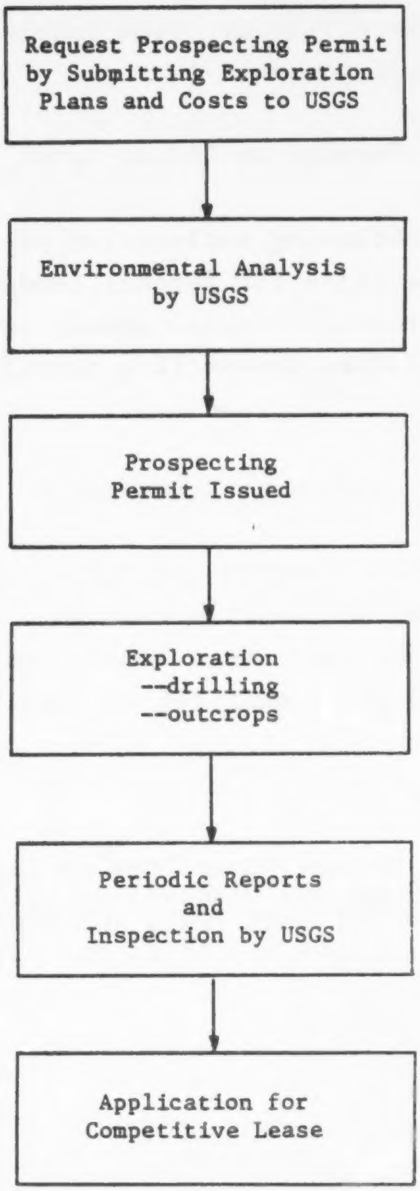
Request Prospecting Permit by Submitting Exploration Plans and Costs to USGS
Environmental Analysis by USGS
Prospecting Permit Issued
Exploration
--drilling
--outcrops
Periodic Reports and Inspection by USGS
Application for Competitive Lease

Figure 3-6. The Sequence of Federal Regulatory Controls Over Exploration.

exercise of reasonable diligence, been unable to determine whether the deposit was workable.[1]

3.5.4b Exploration Permits on Indian Lands

Procedures for obtaining exploration permits for Indian lands are the same as those for federal lands, except that permission from the appropriate Indian agency or authority is also required. However, Indian prospecting permits are not limited in duration.

3.5.4c Exploration Permits on State Lands

Terms of most state permits generally range from ninety days to two years, and are usually renewable. The exploration permit requirements for the eight western states upon which this study is focused are summarized in Tables 3-19 through 3-26.

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[1] U.S., Congress, Senate, Committee on Interior and Insular Affairs. Federal Leasing and Disposal Policies. Hearing Pursuant to S. Res. 45, A National Fuels and Energy Policy Study, 92d Congress, 2d Sess., June 19, 1972, pp. 119-121.

TABLE 3-19. ARIZONA COAL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 27-251	State Land Department, State Land Commissioner
Special Requirements		
Fees	§ 27-251	$25 filing fee
Rental	§ 27-251	$2 per acre up to 640 acres. Permittee must expend at least $10 per acre per year for two years and $20 per acre per year after that
Duration	§ 27-252	One year, renewable to a total of five years
Bond		Required, see § 27-255
Descretionary Actions	§ 27-255	Bond amount determined by Commissioner to cover surface damage
Other Information		

[a] Arizona Revised Statutes Annotated, 1956.

TABLE 3-20. COLORADO COAL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 36-1-140	State Board of Land Commissioners
Special Requirements	§ 36-1-140	Discovery, posting of notice of discovery on site, notify board within ten days of discovery
Fees		
Rental		
Duration	§ 36-1-140	Sixty days, but extension possible
Bond		
Discretionary Actions		
Other Information	§ 36-1-140	At expiration of permit the locator may be required to lease upon agreed-to-terms

[a] Colorado Revised Statutes, 1973.

TABLE 3-21. MONTANA COAL EXPLORATION PERMIT[a]
(For Use of Explosives)

Item	Statutes	Summary
Agency	§ 69-3301	County Clerk and Recorder
Special Requirements		
Fees	§ 69-3304	$5
Rental		
Duration		
Bond	§ 69-3304	$10,000
Discretionary Actions		
Other Information		Any person desiring to do seismographic exploration (with explosives) of any lands in state must apply for this permit

[a] Applies to all minable resources. Revised Codes of Montana, 1947. State land exploration is regulated by leasing procedures explained in Section 1.4.2.3.

TABLE 3-22. NEW MEXICO COAL PROSPECTING PERMIT[a]

Item	Statutes	Summary
Agency	§ 7-10-1	Commissioner of Public Lands
Special Requirements		
Fees	§ 7-8-2	Fees to be set by Commissioner
Rental	§ 7-10-1	Not less than 40 acres, not more than 640 acres
Duration	§ 7-10-1	Not more than one year
Bond		
Discretionary Actions		
Other Information	§ 7-10-3	The prospector receives a preferential right to lease

[a] New Mexico Statutes, 1953.

TABLE 3-23. NORTH DAKOTA COAL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 38-12.1-04	Industrial Commission of the State of North Dakota
Special Requirements	§ 38-12.1-05	If drilling, a permit is required from State Geologist at fee of $100 (if drilling is not required by other state agency)
Fees		
Rental		
Duration	§ 38-12.1-04	Two years with one year extensions to a total of seven years
Bond	§ 38-12.1-04	A reasonable bond may be required by Commission
Discretionary Actions	§ 38-12.1-04	See Bond Requirements
Other Information	§ 38-12.1-04	Applies to all lands in state whether public or private and applies only to coal
	§ 38-12.1-04	Commission has authority to require drilling data from exploration to be delivered to state geologist but kept confidential and may require plugging of all exploratory holes and excavations

[a] North Dakota Century Code, 1960.

TABLE 3-24. SOUTH DAKOTA COAL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 5-7-1	Commissioner of School and Public Lands
Special Requirements		
Fees	§ 5-7-7	$.50 per acre
Rental	§ 5-7-9 § 5-7-7	$.50 per acre per year, maximum of 640 acres
Duration	§ 5-7-7 § 5-7-9	One year, renewable to total of three years
Bond		
Discretionary Actions	§ 5-7-7	The Commissioner, at his discretion, may refuse to issue permit if in best interests of state
Other Information	§ 45-7A-3 § 45-7A-2	A report of any exploratory well drilled must be sent to Department of Natural Resources (will be kept confidential)
	§ 5-7-8	Priority of issue to earliest application date
	§ 5-7-10	Permittee may not remove any minerals
	§ 45-6A-16	Although South Dakota requires a special permit (at a fee of $25) to use heavy equipment in exploration of the surface; this section specifically exempts state lands from that requirement. (The permit is issued by the State Conservation Commission)
	§ 45-7A-2	Wells must be capped, sealed, or plugged

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[a] South Dakota Compiled Laws, 1967.

TABLE 3-25. UTAH COAL EXPLORATION PERMIT[a]

Item	Statutes	Summary
Agency	§ 65-1-18	State Land Board
Special Requirements		
Fees		
Rental	§ 40-1-13	160 acres maximum per township, per person, with $250 worth of work completed every six months per township. No ore to be removed
Duration	§ 140-1-13	One year maximum, with yearly renewals available
Bond		
Other Information	§ 40-6-5	If developer plans to drill (either exploratory or production), the Board of Oil, Gas and Mining has the authority to require: (1) security (for plugging), (2) notice of intent to drill, and (3) filing of well logs

[a] Utah Code Annotated, 1953.

TABLE 3-26. WYOMING COAL EXPLORATION LICENSE[a]

Item	Status
Agency	Department of Environmental Quality
Special Requirements	
Fees	
Rental	
Duration	One year, renewable by letter
Bond	$10,000 minimum
Discretionary Actions	
Other Information	All holes and aquifers must be plugged and dozer trails and drill pods must be completely reclaimed

[a] Wyoming Environmental Quality Act of 1973

3.6 MINING

There are two basic types of mining used to extract coal: surface mining and underground mining. Section 3.6.1 discusses the technologies used in surface mining and presents the input requirements and outputs associated with surface mining technologies. Section 3.6.2 discusses underground mining technologies in a like manner.

3.6.1 Surface Mining

Surface mining operations are increasing at a rate faster than that of total coal production. Total 1976 coal production increased 2.6 percent over 1975 production, while surface mining operations increased 4.8 percent during the same period. Nationwide surface mining accounted for 373 million tons during 1976 or 56 percent of total production.[1] In the western states, surface mining accounts for almost 90 percent of mining operations. The relative growth rate of surface mining operations is depicted in Figure 3-7.

In 1976, total bituminous and lignite coal production in the United States was 665 million tons. Approximately 24.4 percent was produced by the top 50 mines. This is up from 23.1 percent in 1975, thus verifying the trend toward fewer, but larger coal mines, as reported by the Keystone Coal Industry Manual.[2]

3.6.1.1 Technology Description

Surface mining is a general term which refers to any mining method involving the removal of surface material (overburden) to

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[1] Nielsen, George F., ed. 1977 Keystone Coal Industry Manual. New York, New York: McGraw-Hill Mining Publications. 1977.

[2] *Ibid.*

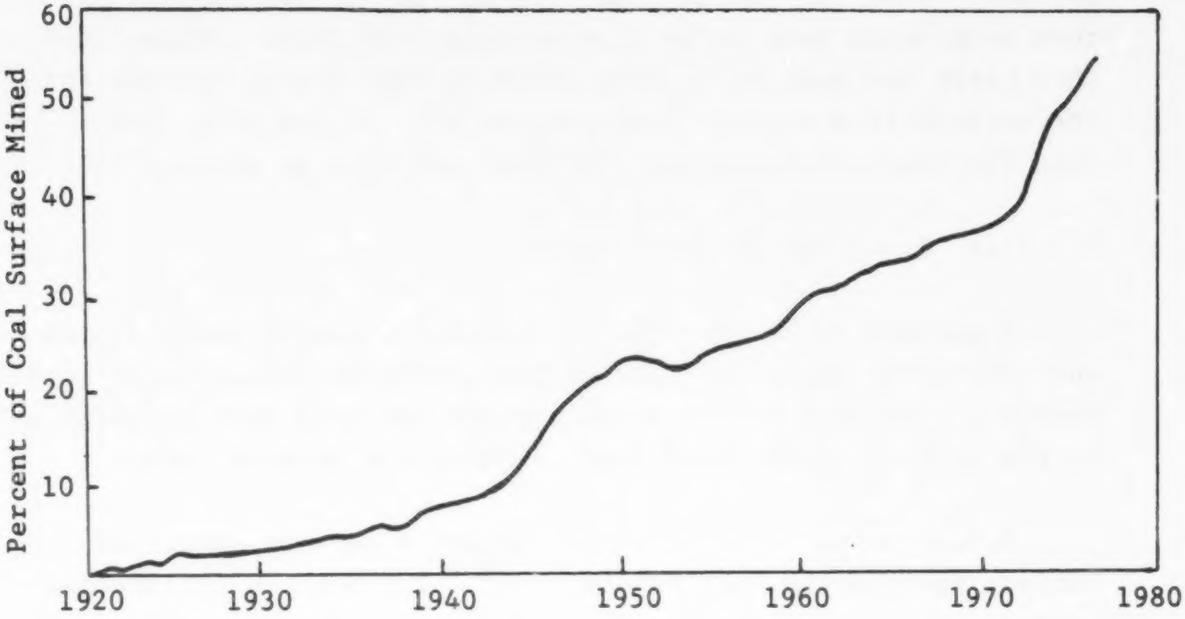

Figure 3-7. Increase in Coal Production by Surface Mining.

Source: Gouse, S. William, Jr. and Edward S. Rubin. A Program of Research, Development and Demonstration for Enhancing Coal Utilization to Meet National Energy Needs, Results of the Carnegie-Mellon University Workshop on Advanced Coal Technology, 1973.

Reprinted from University of Oklahoma, Science and Public Policy Program. Energy Alternatives. A Comparative Analysis. Washington, D.C.: Government Printing Office, 1975.

Extended to 1977 from Nielsen, George F., ed. 1977 Keystone Coal Industry Manual. New York: McGraw-Hill Mining Publications. 1977.

expose an underground resource deposit. There are several factors which must be considered before construction of a surface mine. Probably the most important is the overburden-to-seam thickness ratio. Until about 1965 surface mining of coal was not considered feasible unless the overburden-to-seam thickness ratio was 10:1 or less. Thus, to justify removing 50 feet of overburden, the coal seam would have to be five or more feet thick. Since 1965, this ratio has been increasing and most coal within 150 feet of the surface is now considered economically recoverable, even when the overburden-to-seam thickness ratio is as much as 30:1.

3.6.1.1a Strip Mining (Area Mining)

There are two major types of surface mining: strip mining and contour mining. The conventional strip or area mine is used mainly in relatively flat terrain where the coal seam is parallel to the surface. This technique is ideal for western coals.

Before actual excavation can begin, a certain amount of surface preparation must be performed. The surface preparation phase requires construction of access roads, and maintenance and personnel facilities. Also, utilities must be brought to the site and, in most regions, vegetation must be removed from the area to be mined. Even after the mine is established, additional vegetation removal may be required as the overburden stripping operation advances. After vegetation removal, the top soil is carefully removed and saved for use in the reclamation of the site.[1]

The equipment used in surface preparation consists primarily of bulldozers, scrapers, and loaders and trucks. The trucks are required to transport the salvaged top soil to a stockpile or to an area being reclaimed.

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[1] University of Oklahoma, Science and Public Policy Program. Energy Alternatives: A Comparative Analysis. Washington: Government Printing Office. 1975.

After completing surface preparation, the actual mining operations begin. The strip mine (or area mine) is started with a box-cut or trench extending from one side of the coal field to the other. If the overburden is hard rock or shale, it will have to be fractured by blasting. Six-inch blasting holes are drilled into the rock in a square grid with 15 to 25 foot spacing. A typical blasting charge of 300 pounds of ammonium nitrate and fuel oil packaged in tubes is placed in holes.[1] The blasting material is detonated with electric blasting caps. Larger holes, up to 15 inches in diameter, may be used for harder overburden. A truck or tractor mounted electric rotary drill (or in cases of extremely hard formations, a pneumatic drill) is used to drill the blasting holes. In populated areas, noise control is attempted by covering the explosive cord used in detonating and by introducing milli-second delays in explosion sequences.[2] For safety, blast areas may be covered by mats to minimize the scattering of rock fragments.[3]

Overburden is removed by electric- or diesel-powered stripping shovels or draglines. The uncovered coal is loaded by loading shovels into trucks or conveyors and transported out of the mine, after which the coal is crushed and may be mechanically cleaned. The overburden from each successive parallel cut by the stripping shovel or dragline is deposited on a spoil bank located in the preceding trench. Strip mining has a recovery rate of 80 to 90 percent with coal losses mainly due to spillage and losses in transit.[1] An overall view of the operation is shown in Figure 3-8[2] and an outline of the steps involved in an area mining operation is shown in Figure 3-9.

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[1] Stefanko, Robert R., V. Ramani, and Michael R. Ferko. An Analysis of Strip Mining Methods and Equipment Selection. OCR R&D61, Int. Rept. 7. University Park, PA: Pennsylvania State University, College of Earth and Mineral Sciences. 1973.

[2] Grim, Elmore C. and Ronald D. Hill. Environmental Protection in Surface Mining of Coal. Washington: Environmental Protection Agency. 1974.

[3] *Ibid.*

The depth of overburden which can be removed economically will depend on the thickness of the coal seam. As a rule, area mining can be performed where overburdens are not more than 200 feet thick.[3] Greater depths may become economically feasible in the future depending on technology, economics, and environmental concerns.

3.6.1.1b Contour and Auger Mining

Contour and auger mining are performed in hilly terrains that are not amenable to strip mining. The initial surface preparation activities are essentially the same as for strip mining. The main difference is that in contour mining, the mine is excavated in a path following the terrain of the particular area. The mining equipment used in contour mining is generally smaller than that used for strip mining.[4] When the high wall of the mine becomes too high for strip mining, augers are used to recover additional coal. In auger mining large augers are driven horizontally about 200 feet into a coal seam.[5] Coal is recovered in the form of chips similar to wood chips from a

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[1] Stefanko, Robert R., V. Ramani, and Michael R. Ferko. An Analysis of Strip Mining Methods and Equipment Selection. OCR R&D61, Int. Rept. 7. University Park, PA: Pennsylvania State University, College of Earth and Mineral Sciences. 1973.

[2] U.S. Environmental Protection Agency. Processes, Procedures, and Methods to Control Pollution from Mining Activities. Washington: Government Printing Office. 1973 .

[3] Stefanko, Robert R., *op.cit.*

[4] *Ibid.*

[5] U.S. Environmental Protection Agency, *op.cit.*

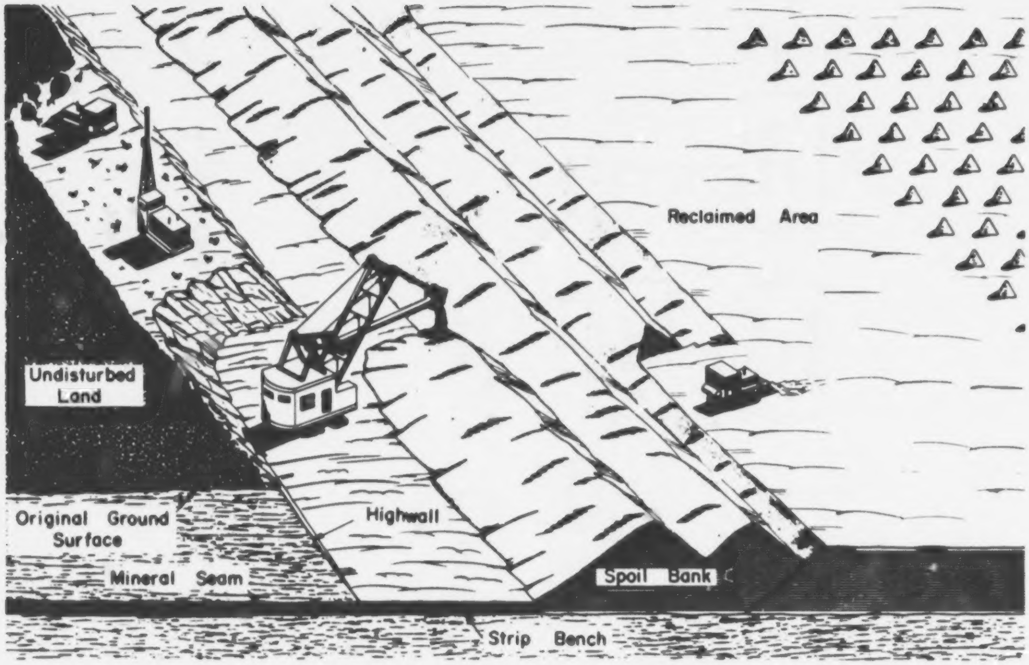
Reclaimed Area
Undisturbed Land
Original Ground Surface
Highwall
Mineral Seam
Spoil Bank
Strip Bench

Figure 3-8. Area Mining.

Source: U.S. Environmental Protection Agency. Processes, Procedures, and Methods to Control Pollution from Mining Activities. Washington: Government Printing Office, 1973.

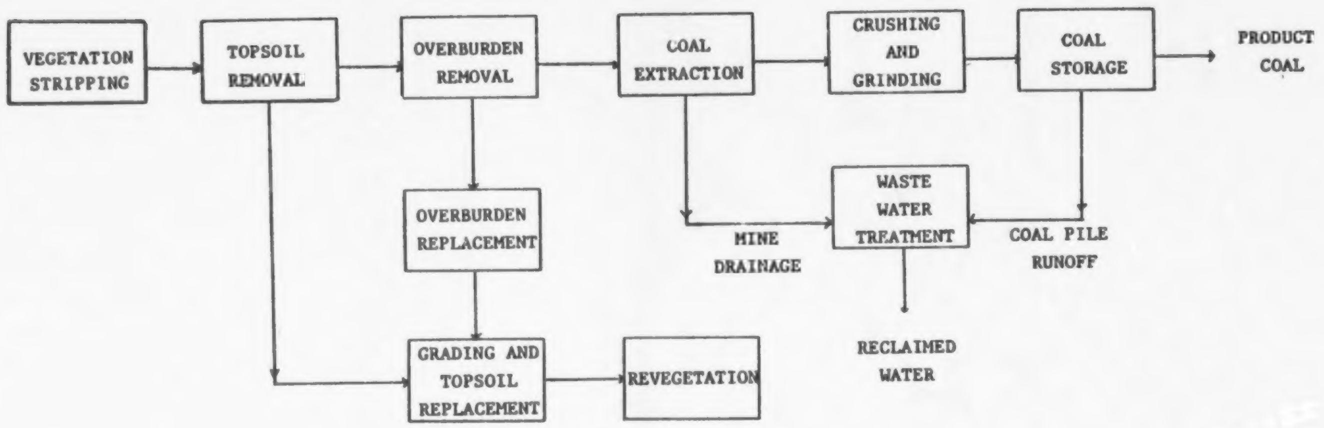
VEGETATION STRIPPING
TOPSOIL REMOVAL
OVERBURDEN REMOVAL
COAL EXTRACTION
CRUSHING AND GRINDING
COAL STORAGE
PRODUCT COAL
OVERBURDEN REPLACEMENT
MINE DRAINAGE
WASTE WATER TREATMENT
COAL PILE RUNOFF
RECLAIMED WATER
GRADING AND TOPSOIL REPLACEMENT
REVEGETATION

Figure 3-9. Steps Involved in an Area Mining Operation.

drill bit. The introduction of dual and multiple augers has helped increase the percent recovery of coal from thin seams. The auger holes are backfilled and plugged by special compaction techniques. Recovery rates for auger mining are thought to be around 50 percent but may be as low as 30 percent in actual operation.[1] The major losses are from coal left between the auger holes. Although these two mining methods are not widely used outside of the Appalachian coal region of this country, they are now receiving consideration in some western regions.

3.6.1.1c Excavation Techniques

With the advent of larger surface mining operations, specialized pieces of equipment have evolved to cope with the various surface mining methods. Although overburden removal was discussed in the section on strip mining, a number of technological alternatives are available for this removal and should be discussed further.

Four kinds of equipment are used in typical surface mining operations: small, mobile tractors, including bulldozers, scrapers, and front-end loaders; shovels; draglines; and wheel excavators.

Most mining operations will use several of these equipment items in varying combinations, although one or two usually dominate the operation. Item selection and combination are generally based on the nature and quantity of the material to be moved, distance and transport surface conditions, and flexibility of the equipment for other applications.[1] Descriptions of the major mining equipment items follow:

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[1] Stefanko, Robert R., V. Ramani, and Michael R. Ferko. An Analysis of Strip Mining Methods and Equipment Selection. OCR R&D60, Int. Rept. 7. University Park, PA: Pennsylvania State University, College of Earth and Mineral Sciences. 1973.

- Tractors. Tractors or front end loaders are typically used either in small mines or in conjunction with larger, more specialized equipment in large mines. The principal advantages of tractors are their maneuverability, ability to negotiate steep grades, and capability to dig and transport their own loads.[2] Tractors are used for a variety of tasks, including clearing, preparing benches, leveling spoil piles, and constructing roads.

- Shovels. Large diesel or electrically powered stripping shovels have been used in surface mines for a number of years and are often designed for a particular mine application. These machines progress along a bench scooping up the fragmented overburden or coal in buckets with capacities of up to 130 cubic yards. In the largest surface mines, shovels are often used in conjunction with draglines, primarily to load coal.

- Draglines. Electrically powered draglines, such as the one shown in Figure 3-10 are capable of moving larger amounts of materials in a single bite than any other equipment item currently being used in surface mines. Bucket capacity of these machines ranges from 10 to 220 cubic yards. The dragline moves along the bench, positions its bucket on the overburden to be removed,

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[1] Killebrew, Clarence E. "Tractor Shovels, Tractor Dozers, Tractor Scrapers." In E.P. Pfleider, ed. Surface Mining. New York: American Institute of Mining, Metallurgical and Petroleum Engineers. 1968. pp. 463-477.

[2] *Ibid.*

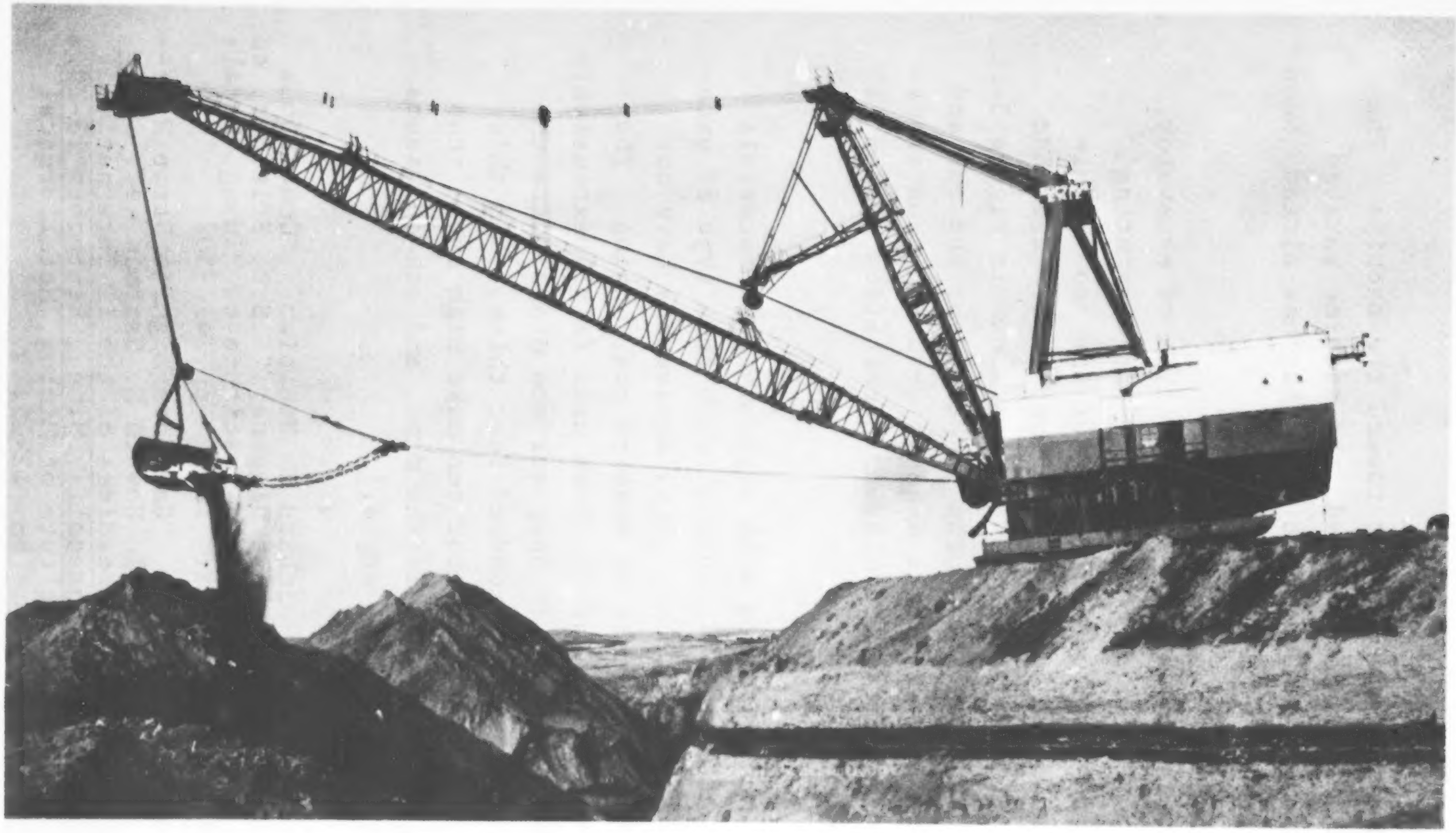

Figure 3-10. Dragline.

Source: National Petroleum Council, Committee on U.S. Energy Outlook, Other Energy Resources Subcommittee. *U.S. Energy Outlook: An Initial Appraisal by the Oil Shale Task Group, 1971-1985*. Washington: NPC, 1972.

and loads it by dragging it toward the machine. The loaded bucket is then lifted, the machine rotated, and the bucket dumped in an area that has already been mined.

Bucket Wheel Excavators. Another type of excavator, although seldom used in the U.S., has a rotating bucket wheel mounted at the end of the boom. This bucket wheel can be 50 or more feet in diameter and the boom up to 400 feet long.[1] As shown in Figure 3-11, rotating the wheel loads the buckets from the cut and empties the material onto a conveyor which then transports it to whatever in-mine transportation system is being used.

Only the largest mines with suitably soft materials justify the expense associated with this type of excavator. Currently bucket wheel excavators have not been used with success in western coal mining. The bucket wheel excavator has been used fairly extensively in Europe, generally in deep surface mines where the overburden is several hundred feet thick.[2] In this type of mine, the excavator can make high cuts, thus requiring fewer levels in the mine, and can cut seams that have a high slope angle.[3]

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[1] Aiken, George E., and Reinhard P. Wohlbier. "Continuous Excavators (Bucket Wheel and Chart Diggers)." E.P. Pfleider, ed. Surface Mining. New York: American Institute of Mining, Metallurgical and Petroleum Engineers. 1968. pp. 478-502.

[2] Gartner, Ing. E. H. Ervin. "Garsdorf Lignite Strip Mine--Operations to Unusual Depths." In Howard L. Hartman, ed. Case Studies of Surface Mining: Proceedings of the II International Surface Mining Conference, Minneapolis, Minn., September 18-20, 1968. New York: American Institute of Mining, Metallurgical and Petroleum Engineers. 1969. pp. 12-35.

[3] *Ibid.*

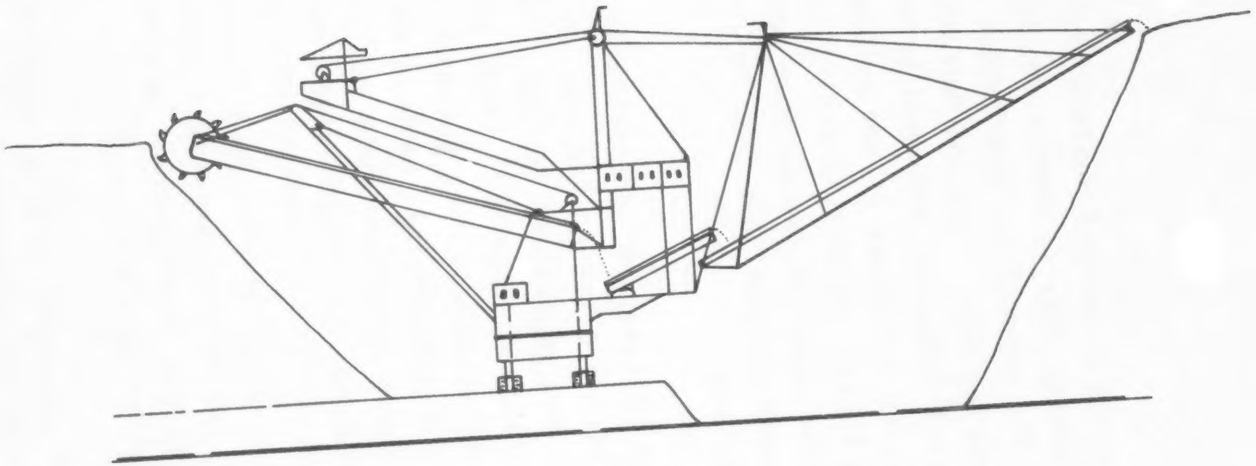

Figure 3-11. Bucket Wheel Excavator.

Source: Weimer, W. Henry, and Wilbur A. Weimer. "Surface Coal Mines," Arthur B. Cummins and Ivan A. Given, eds. SME Mining Engineering Handbook. New York: American Institute of Mining, Metallurgical and Petroleum Engineers, 1973, pp. 17-151.

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Whatever the method used, area and contour mines require large energy inputs for equipment operation and have high materials outputs.

3.6.1.1d Reclamation

Reclamation is an integral part of surface mining operations. As coal extraction of a mining area is completed, that area becomes the receptacle for the topsoil and overburden that must be removed from the active mining site. The overburden is replaced first and graded to original contours, followed by topsoil replacement. Thus, reclamation continues at the same pace as the mining operation, lagging behind the mining activities by a fixed time period, probably on the order of two or more months. This section will discuss the common items that must be considered when planning reclamation activities.

Natural constraints on reclamation, particularly as it applies to revegetation, include climatic factors, soil conditions, overburden characteristics, and vegetation ecology. Many of the technologies presently available to cope with these constraints are still in the experimental stage and have not been applied at the scale at which they would ultimately have to be applied in practice. Furthermore, these techniques have not yet been developed to a point where successful revegetation can always be assured. The present "state-of-the-art" permits mine operators to improve the suitability of spoil material as a plant growth medium, but local conditions beyond the operator's control determine whether this improvement is sufficient to permit the establishment of a self-perpetuating plant cover.

The available choices of potential land use after mining are greatest in those areas with the best soils and most favorable soil moisture conditions. In general, the reclamation goals most often cited are: approximate original contour; restore texture and fertility for use as cropland; establish improved wildlife habitat; develop recreational amenities, usually with the inclusion of water-based recreation; and convert to urban or industrial use, which does not require extensive rehabilitation.[1]

3.6.1.2 Input Requirements

The construction and operation of a surface coal mine requires an influx of labor, material and equipment, capital, water, land availability, and outside energy. Each of these input requirements will be discussed in the following sections for an example coal mine. The example coal mine is being surface mined at an annual production rate of 12 million tons - enough to supply a 3000 MW power plant or a 30,000 ton/day coal conversion plant. The example mine is assumed to be located in the San Juan river basin with a 70 foot overburden and a 10 foot seam thickness. For a 12 million tons/year mine, there will be three separate active mining sites, each producing 4 million tons of coal per year. A general layout of the mine showing the three separate mining areas is shown in Figure 3-12.

3.6.1.2a Manpower Requirements

For any operation there are two distinct phases; the construction phase, followed by the continuous mining operations. Manpower requirements for both phases depend on the size and type of mining operation involved. Manpower requirements for the construction phase will also depend on the duration of the construction activity. The longer the construction time, the fewer the number of construction personnel needed. A surface

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[1] Reclamation of strip-mined lands is discussed as an impact of coal resource development in: White, I.L., *et al*. Energy From the West: A Progress Report of a Technology Assessment of Western Energy Resource Development. Washington: U.S. Environmental Protection Agency. 1977. Chapter 12.

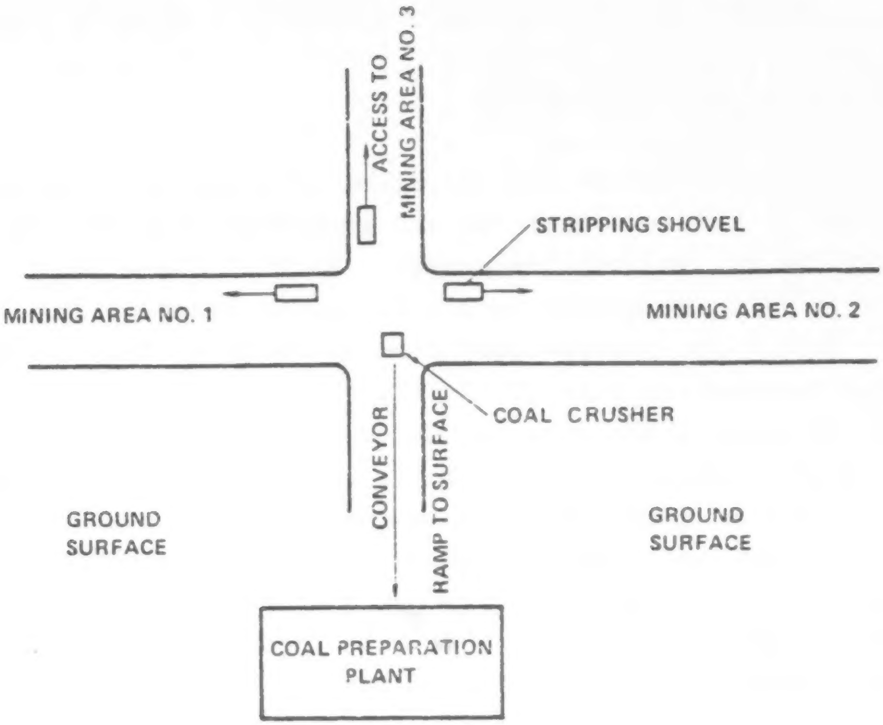
ACCESS TO
MINING AREA NO. 3
STRIPPING SHOVEL
MINING AREA NO. 1
MINING AREA NO. 2
COAL CRUSHER
CONVEYOR
RAMP TO SURFACE
GROUND
SURFACE
GROUND
SURFACE
COAL PREPARATION
PLANT

Figure 3-12. Sketch of Mine Plant.

mine could be prepared and producing within one year from date field work begins. However, since most processing/conversion facilities in a mine-mouth operation will take five or more years to construct, construction of the surface mine is defined to take 5 years as well. Assuming a five year construction schedule, Bechtel Corporation has estimated that a maximum of approximately 210 workers will be employed during the second, third, and fourth years of construction.[1] The schedule and number of workers to be employed, by skill, is reflected in Table 3-27.

Manpower requirements for operating the example 12 MM TPY surface mine described above are shown in Table 3-28. These requirements were estimated using Bechtel Corporation's Energy Supply Model, a computer program based on Bechtel Corporation's construction and engineering experience.[2]

3.6.1.2b Materials and Equipment

Table 3-29 lists the major construction materials required for construction of a 12 million ton per year strip mine, based on Bechtel Corporation's Energy Supply Model.[3] Major equipment items required for the operation of a 12 million ton per year strip mine are presented in Table 3-30.[4] The operating equipment

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[1] Carasso, M. *et al.* Energy Supply Model, Computer Program. San Francisco: Bechtel Corporation. 1975.

[2] *Ibid.*

[3] *Ibid.*

[4] Ralph M. Parsons Co. Commercial Complex Conceptual Design/Economic Analysis, Oil and Power by COED Based Coal Conversion. Pasadena, CA: Ralph M. Parsons Co. 1975. p. 10-2.

TABLE 3-27. SCHEDULE OF MANPOWER RESOURCES REQUIRED FOR CONSTRUCTION OF SURFACE WESTERN COAL MINE REQUIRED TO PRODUCE 12 MM TPY COAL

Resources	Manpower Requirements (man-years)				
	yr 1	yr 2	yr 3	yr 4	yr 5
Civil Engineers	3	16	11	16	9
Electrical Engineers	1	5	4	5	3
Mechanical Engineers	1	6	4	6	3
Mining Engineers	1	8	6	8	4
Geological Engineers	0	1	1	1	0
Other Engineers	0	2	1	2	1
TOTAL ENGINEERS	7	38	27	38	20
TOTAL DESIGNERS + DRAFTSMEN	5	27	19	27	14
TOTAL SUPERVISORS + MANAGERS	2	13	9	13	7
TOTAL TECHNICAL	14	78	55	78	41
TOTAL NON-TECH (NON-MANUAL)	2	10	10	10	8
Pipefitter/Welders	0	1	1	1	1
Electricians	1	6	7	6	6
Iron Workers	3	20	22	20	19
Carpenters	1	9	10	9	8
Operating Engineers	6	38	43	38	37
Other Major Skills	3	16	18	16	16
TOTAL MAJOR SKILLS	14	89	102	89	88
OTHER CRAFTSMEN	2	9	11	9	9
TOTAL CRAFTSMEN	16	99	113	99	97
TOTAL TEAMSTERS + LABORERS	4	24	27	24	23
GRAND TOTALS	36	211	205	211	169

Source: Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

TABLE 3-28. MANPOWER RESOURCES REQUIRED FOR OPERATION AND MAINTENANCE OF A SURFACE WESTERN COAL MINE PRODUCING 12 MM TPY COAL

Classification	Number Required
Electrical Engineers	1
Mechanical Engineers	1
Mining Engineers	3
Other Engineers	2
Total Engineers	6
Total Designers + Draftsmen	4
Total Supervisors + Managers	43
Total Other Technical	38
Total Technical	92
Total Non-Tech (Non-Manual)	31
Electricians	34
Equipment Operators	101
Other Operators	10
Other Major Skills	182
Total Major Skills	327
Total Craftsmen	327
Total Teamsters + Laborers	102
GRAND TOTAL	552

Source: Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

TABLE 3-29. MAJOR EQUIPMENT ITEMS REQUIRED FOR SURFACE MINING 12 MM TPY COAL

Number	Description	Size
13	Portable Light Towers	
3	Mine Pumping Systems	
3	Hydraulic Cranes	15 ton
3	Mobil Cranes	50 ton
3	Screw Compressors	600 cu ft
13	Rotary Blasthole Drills	
3	Track Drills	
3	Stripping Shovels	140 cu yd
3	Holland Loaders	
3	DDOGs	
3	Coal Shovels	12 cu yd
3	Front-End Loaders	10 cu yd
16	Coal Haulers	120 ton
7	D-9s with Ripper & Dozer	
3	D-8s with Dozer	
3	Wheel Dozer	
3	Grader	
3	Lube-Fuel Trucks	
3	Water Sprinkler Trucks	
3	ANFO Trucks	
3	Trucks	3 ton
3	Trucks	5 ton
3	Lowboy with Tractor	50 ton
1	Passenger Bus	40 passenger
1	Fire Truck	
16	Pickup Trucks	
6	Flat Bed Trucks	3 ton
6	Flat Bed Trucks	5 ton

Source: Ralph M. Parsons Co. Commercial Complex Conceptual Design/Economic Analysis, Oil and Power by COED Based Coal Conversion. Pasadena, CA: Ralph M. Parsons Co., 1975. p. 10-2.

estimates are based on a conceptual design by Ralph M. Parsons Co. of a strip mine mining 13 million tons per year which reduces to 12 million tons per year after coal cleaning.

TABLE 3-30. CONSTRUCTION MATERIALS REQUIRED FOR A 12 MM TPY SURFACE MINE

Resources	Quantity
Cement (tons)	62800
Pipe + Tubing (less than 24 inch) (tons)	608
Structural Steel (tons)	940
Reinforcing Bar (tons)	1180
Draglines (net capacity, cu yds)	180
Draglines (net capacity, tons)	10400

Source: Carasso, M., *et al.* Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation. 1975.

3.6.1.2c Economics

An itemized list of the capital costs associated with the development of a 13 million ton per year coal strip mining operation is presented in Table 3-31. Table 3-32 presents the annual operating costs associated with the same mining operation. These costs are in 1974 dollars, and were developed by Ralph M. Parsons Co. based upon the detailed conceptual design of a coal liquefaction complex located in the Illinois-Kentucky coal region.[1] Based on these cost estimates a 12 million ton per year strip mine would require a total capital investment of approximately 105 million dollars and an annual operating cost of 46 million dollars.

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[1] Parsons, Ralph M., Company. Commercial Complex Conceptual Design/Economic Analysis, Oil and Power by COED Based Coal Conversion. R&D Report for Energy Research and Development Administration Contract E(49-18)-1775, Pasadena, CA: U.S. Government Printing Office. September 1975. p. 12-12.

TABLE 3-31. COAL MINE EQUIPMENT COSTS AND REPLACEMENT SCHEDULE (1974 DOLLARS) (13 MILLION TONS/YR)

Equipment Item	Delivered Cost ($000)	Useful Life (yr)	Annual Depreciation ($)
Stripping Shovels (3)	52,770	20	2,638,500
Holland Loaders (3)	614	5	122,800
DD9G-s for Holland Loaders (3)	746	4	187,000
Coal Shovels, 12 cu yd (3)	2,136	7	305,143
Coal Haulers, 120 ton (15)	3,391	4	847,750
Front-End Loaders, 19 cu yd (3)	580	3	193,333
D-9's w/Ripper and Dozer (6)	950	3	316,667
D-9's w/Dozer (6)	859	3	286,333
D-8's w/Dozer (3)	302	3	100,667
Wheel Dozer (3)	405	3	135,000
Grader (3)	182	3	60,667
Rotary Blast-Hole Drills (12)	3,878	5	775,600
Portable Light Towers (12)	72	5	14,400
Track-Drills (3)	106	3	35,333
Screw Compressors, 600 cu ft (3)	85	3	28,333
Lube-Fuel Truck (3)	90	3	30,000
Water Sprinkler Truck (3)	423	3	141,000
AN/FO Trucks (3)	85	4	21,250
Trucks, 3 ton	16	5	3,200
Trucks, 5 ton	19	5	3,800
Mine Pumping Systems	150	10	15,000
Hydraulic Cranes, 15 ton (3)	207	4	51,750
Mobile Crane, 50 ton (3)	431	20	21,550
Lowboy w/Tractor, 50 ton (1)	31	20	1,550
Bus, 40 Passenger (1)	21	7	3,000
Tire Truck (1)	51	7	7,285
Pickup Trucks (15)	53	3	17,667
Flatbed Trucks, 3 ton (8)	26	5	5,200
Flatbed Trucks, 5 ton (8)	32	5	6,400
Total Equipment	68,719		6,376,478
Preproduction Costs	27,581	10	2,758,100
Subtotal	96,300		9,134,578
Home Office Engineering and Sales Tax	7,700	10	770,000
TOTAL Equipment Costs	104,000		9,904,578
Start up Costs	1,000		
Construction Financing	8,500		
Total Depreciable Investment[a]	113,500		

[a] Total depreciable investment is equivalent to 8.7 $/ton

Source: Parsons, Ralph M., Company. Commercial Complex Conceptual Design/ Economic Analysis, Oil and Power by CCED Based Coal Conversion. R&D Report for Energy Research and Development Administration Contract E(49-18)-1775, Pasadena, CA: U.S. Government Printing Office, September 1975. p. 12-12.

TABLE 3-32. ANNUAL OPERATING COST SUMMARY (1974 DOLLARS) (13 MILLION TONS/YR)

Item	Cost $ million/yr
Mine Royalty	11.781
Materials and Supplies	
Operating Supplies	2.817
Equipment Operation	10.520
Total Materials and Supplies	13.337
Labor	
Operating Labor and Supervision	6.159
Maintenance Labor and Supervision	1.537
Plant Overhead	1.924
Payroll Burden	3.367
Union Welfare	7.234
Total Labor Costs	20.221
G and A Overhead	0.743
Miscellaneous Costs	
Reclamation	0.042
Permits and Bonds	0.275
Miscellaneous	0.030
Total Miscellaneous Costs	0.347
Taxes and Insurance	3.120
Total Operating Costs[a]	49.549

[a] Total operating costs excluding depreciation are equivalent to 3.8 $/ton.

Source: Parsons, Ralph M., Company. Commercial Complex Conceptual Design/Economics Analysis, Oil and Power by COED Based Coal Conversion, R&D Report for Energy Research and Development Administration Contract E(49-18)-1775, Pasadena, CA: U.S. Government Printing Office, Sept. 1975. p. 12-12.

Table 3-33 presents a comparison of surface mining costs at four Western mines. These costs were developed by Skelly and Loy in a detailed study of mining and reclamation costs for the Bureau of Mines.[1] In this study it was determined that typical operating costs for mining in the western states ranged from \$4.29 to \$6.84 per ton of coal (1974 dollars). In addition, mining costs were found to be most dependent on mine size, overburden thickness, seam thickness, and topography. Coal heating value is also important when considering costs per unit energy.

The coal costs presented in Table 3-33 include the costs associated with top soil removal and reclamation activities. As envisioned in this assessment by Skelly and Loy, reclamation costs range from 0.1 to 0.3 \$/ton of coal, and depend on the same factors listed above for coal costs.

3.6.1.2d Water Requirements

The process water requirements of the mining operations primarily consists of water used for dust control in the crushing plant and along haulage roads. Personnel water requirements are generally negligible. All of the water required to satisfy these demands is normally available in the form of reclaimed water collected as mine drainage or surface run-off. Another source of water for this use is wastewater from power plants or coal conversion plants. Many of their wastewaters are highly suitable for dust control. Low quality ground waters are also excellent mine water sources.

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[1] Skelly and Loy. Economic Engineering Analysis of U.S. Surface Coal Mines and Effective Land Reclamation. Final Report for U.S. Bureau of Mines, Contract S0241049. Harrisburg, PA: U.S. Government Printing Office, PB-245315. February 1975. p. 9-220.

TABLE 3-33. COMPARISON OF WESTERN SURFACE MINING COSTS (1974 DOLLARS)

Item	Mine 1	Mine 2	Mine 3	Mine 4
State	Colorado	Wyoming	Montana	North Dakota
Type	strip	open pit	strip	strip
Production (million ton/yr)	1.8	3.0	5.0	2.0
Overburden (ft)	70	100	65	60
Seam Thickness (ft)	7	27	52	20
Capital Investment				
($ million)	20.7	25.0	30.2	17.1
($/ton)	11.50	8.33	6.04	8.55
Operating Costs[a]				
Excluding depreciation ($/ton)	5.16	3.39	3.41	3.23
Including depreciation ($/ton)	6.84	4.72	4.29	4.62

[a] Cost basis is 20 yr equipment life and 15% interest on investment.

Source: Skelly and Loy. Economic Engineering Analysis of U.S. Surface Coal Mines and Effective Land Reclamation, Final report for U.S. Bureau of Mines Contract 50241049, Harrisburg PA: U.S. Government Printing Office PB-245315, Feb. 1975. p. 9-220.

Water requirements for reclamation have been estimated to vary from 0.5 to 0.75 acre feet per acre per year.[1] Reclamation water requirements are highly variable, depending on soil conditions, climate, and vegetation. Water used for reclamation must also be of higher quality than water used for dust control. Assuming that reclaimed land will be irrigated for ten years, then based on a land disturbance of 670 acres/year (see following Land Requirement Section), 3350 to 5025 acre-feet/year of water will be required for reclamation.

3.6.1.2e Land Requirements

There are two categories of land requirements for a surface coal mine: 1) the incremental or active land area required by the stripping of the overburden and the actual mining of the coal, and 2) the fixed land area required for the permanent facilities at the mine. For a western strip mine with a coal seam thickness of 10 feet, approximately 1.8 acres/day is disturbed to produce 12 million tons of coal per year. Generally reclamation activities will commence 100 days after topsoil and overburden removal activities are initiated at any given location.[2] As a result, at any given time the land area designated as the active working area is estimated to be equal to the land area disturbed in 100 days of mining activity. For the example strip mine used in this study, the active working component of the land area requirements is 180 acres. Over the 30 year mine life, the total acreage of land consumed is about 20,000 acres.

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[1] National Academy of Engineering. Rehabilitation Potential of Western Coal Lands. A Report to the Energy Policy Project of the Ford Foundation. Cambridge, MA: Ballinger. 1974.

[2] *Ibid.*

The fixed land requirements include the space occupied by the processing and loading facilities, the land needed to store the initial cut refuse, and the land area occupied by the water containment facility. Haulage roads have been estimated to occupy from 6 to 12 acres, and processing and loading facilities have been estimated to occupy approximately 43 acres.[1]

Although not actually considered a land requirement, additional land area will be continuously undergoing reclamation. Currently, the Surface Mining Control and Reclamation Act requires that reclamation activities be conducted for ten years after an area is mined.[2] Under this requirement approximately 6700 acres of land will be involved in reclamation activities after the mine is established.

Surface mining land requirements are summarized in Table 3-34. As the table indicates, surface mines with thicker coal seams will have lower land requirements, for the same output.

TABLE 3-34. LAND AREA REQUIREMENTS FOR A 12 MILLION TPY COAL STRIP MINE

Usage	Mine 1	Mine 2
Coal Seam Thickness (ft)	10	20
Active Working Area (acres)	180	90
Reclamation Area (acres)	6700	3350
Fixed Land Requirement		
Haulage roads (acres)	6-12	6-12
Processing and loading (acres)	43	43

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[1] National Academy of Engineering. Rehabilitation Potential of Western Coal Lands. A Report to the Energy Policy Project of the Ford Foundation. Cambridge, MA: Ballinger. 1974.

[2] Surface Mining Control and Reclamation Act of 1977, Pub. L. 95-87, 91 Stat. 445.

3.6.1.2f Ancillary Energy

Two forms of ancillary energy are required for surface mining operations; electricity and diesel fuel. The larger draglines and the coal crushers are electrically powered. The smaller earth movers and trucks are diesel engine powered. Hittman has reported energy requirements for several surface mining activities.[1] The values reported in Table 3-35 have been extrapolated from the Hittman data to a 12 million TPY surface mine in the Western United States.

TABLE 3-35. ANNUAL ANCILLARY ENERGY REQUIREMENTS FOR A 12 MILLION TPY COAL STRIP MINE

Operation	Electricity (10^6 kWh/yr)	Diesel Fuel (10^3 gal/yr)	Total Energy[a] (10^9 Btu/yr)
Mining	10-20	700-1300	200-400
Hauling		300-600	40-80
Crushing	40	450	450
Reclamation		10-40	2-6
Total	50-60	1700-2000	700-900

3.6.1.3 Outputs

The outputs associated with a coal surface mine are very site and size dependent. Overburden and seam thickness have a direct effect on the quantity and quality of outputs from a surface mine. This section presents the outputs from an example 12 million ton per year coal mine located in the Western United States. The overburden is assumed to be 70 feet thick and the coal seam is assumed to be 10 feet thick.

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[1] Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use. Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, MD: Hittman Associates, Inc. 1974 and 1975.

The various outputs associated with surface mining include air emissions, water effluents, solid wastes, and noise. Each of these is examined in the following sections. Occupational safety is also considered a form of output and will be examined at the end of this section. No odors have been identified as being associated with strip mining activities. This output will not be discussed.

3.6.1.3a Air Emissions

Potential sources of airborne emissions from surface mining activities include dust and other materials emitted during the blasting and materials handling operations, major combustion products released by the diesel oil-fueled equipment used in mining operations, and wind-blown dust from mines and waste piles. In some surface mining operations, waste piles ignite spontaneously and burn, releasing products of combustion and other unburned materials into the atmosphere. A summary of the airborne emissions in a western mine is found in Table 3-36.

TABLE 3-36. AIR EMISSIONS FROM A 12 MILLION TPY COAL SURFACE MINING OPERATION[1]

Emission Source	Production Rate	Emission Rate lbs/hr					
		Particulates	CO	NO_x	SO_2	Hydrocarbons	CO_2
Diesel engines	250 gal/hr	6	23	100	8	8	5500
Fugitive dust							
Coal mining	1375 ton/hr	1100	-	-	-	-	-
Reclamation	180 acres	600	-	-	-	-	-
Coal crushing	1375 ton/hr	7	-	-	-	-	-

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[1] U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. EPA Publication AP-42. Research Triangle Park, NC: U.S. Government Printing Office. 1977. p. 3.2.7.

The diesel fuel emissions are based upon the ancillary fuel requirements presented in Table 3-35 and calculated by using EPA emission factors for heavy duty construction equipment. Particulate emission rates from materials handling and wind erosion are difficult to quantify. Very little data is available on these sources. Coal mining and reclamation emission rates presented in Table 3-36 are based upon general fugitive dust emission factors developed by EPA. These are presented in Table 3-37. Actual dust emissions are highly dependent on wind and rain rates, soil conditions, and dust suppression measures. A dust control efficiency of 40% was assumed for mine area dust suppression activities such as watering. The emission factors for coal crushing were also developed by EPA and include an emission control efficiency of 99% (crusher enclosures and bag filters).[1]

TABLE 3-37. EMISSION FACTORS FOR MINING EMISSION SOURCES

Source	Particulates	CO	NO_x	SO_2	Hydrocarbons	CO_2
Diesel engines ($lb/10^3$ gal)[a]	25	90	400	31	31	22,000
Fugitive dust (lb/ton)[b]	.8					
Reclamation (ton/acre-mo)[c]	.7					
Coal crushing (lb/ton)[d]	.005					

[a] U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. EPA publication AP-42, Research Triangle Park, NC: U.S. Government Printing Office. 1977. p. 3.2.7.

[b] *Ibid.*, p. 11.2.3

[c] *Ibid.*, p. 11.2.4

[d] *Ibid.*, p. 8.20

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[1] U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. EPA Publication AP-42. Research Triangle Park, NC: U.S. Government Printing Office. 1977. p. 3.2.7

3.6.1.3b Water Effluents

Potential pollutants of streams and underground water supplies from coal surface mining operations include iron, silt and trace metals such as arsenic, copper, lead, manganese, zinc, nitrates and sulfates. Due to the alkalinity of the subsurface rock in the western coal fields and the low sulfur levels in the coal, pollution by dissolved acids such as sulfuric is not a problem. Surface mining pollutants are eroded from the solid waste piles, or spoil, and leached from the exposed underlying rock by rain runoff. Fortunately, very few mining areas yet found in New Mexico or Wyoming have intersected groundwater. This is expected to be the rule throughout the western states. Also, due to the limited rainfall in this area, most mine drainage and surface runoff is recovered and used to satisfy mining operation water requirements such as dust control in the crushing plant and along haulage roads. Therefore, no significant effluent streams are anticipated from future western mines.

3.6.1.3c Solid Wastes

Solid wastes from mining vary considerably as a function of surface mining technique, and overburden depth. In area strip mining, solid wastes are produced only by the initial box cut made to open the mine (five acres). Subsequently, removed overburden is deposited in spoil banks in the excavated area. The quantity of the initial overburden, if 70 feet thick, is $15\text{x}10^6$ ft^3 or approximately $750\text{x}10^3$ tons.

Although surface mines are used for the disposal of additional solid wastes such as fly ash and waste sludges from beneficiation, these solid wastes are not attributable to the coal mine itself.

3.6.1.3d Noise Pollution

Noise will be a problem within the plant due to use of heavy machinery and explosives in breaking and loading the overburden. However, the plant is large enough (20,000 acres) that noise is not considered a problem at the plant boundary.

3.6.1.3e Occupational Health and Safety

Hittman[1] has estimated occupational health statistics for a surface mine in the Powder River Basin to be: 9.91 deaths, 34.1 injuries, 2252 lost man-days for every 10^{12} Btu of coal extracted. Adjusting these figures to a 12 MM TPY mine in Colstrip, Montana, one might expect the annual health statistics to be: 19 injuries, 1300 lost man-days, and one death every two years.

3.6.1.4 Summary

Table 3-38 presents a summary of the direct impacts from a 12 MM TPY surface mine located at the Navajo scenario.

3.6.2 Underground Mining

3.6.2.1 Technology Description

The two basic underground mining methods used in the United States are: room and pillar, and longwall. In both types of mining, the initial step is to prepare the surface facilities, including the constructing of access roads and structures, bringing the necessary utilities to the site, clearing vegetation from the construction site, and locating tunnels and shafts.

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[1] Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, MD: Hittman Associates, Inc. 1974 and 1975.

TABLE 3-38. SUMMARY OF IMPACTS ASSOCIATED WITH 12 MM TPY SURFACE MINE AT NAVAJO

Inputs	
Manpower	
• construction	832 man-years
• operating	552 men
Materials and Equipment	
• stripping shovels (140 cu yd)	3
• cement (tons)	62,800
• structured steel (tons)	940
• draglines (tons)	10,400
Economics[a]	
• capital cost (estimated)	\$104 million
• annual operating cost (estimated)	\$ 46 million
Water (reclamation)	4,000 acre-ft/yr
Land	20,000 acres (30 yr total) 240 acres (at a time)
Ancillary Energy	
• electricity	55×10^6 kwhr/yr
• diesel fuel	1.8×10^6 gal/yr
Outputs	
Air Emissions	
• hydrocarbons	8 lb/hr
• particulates	1700 lb/hr
• SO_2	8 lb/hr
• NO_x	100 lb/hr
• CO	23 lb/hr
• CO_2	5500 lb/hr
Water Effluents	Recycled
Solid Wastes	Returned to mine
Noise Pollution	Insignificant
Occupational Health and Safety	
• deaths	0.6 deaths/yr
• injuries	19 injuries/yr
• lost man-days	1300 man-days/yr

[a] 1974 dollars

The equipment used for these tasks basically is the same as that used for surface mines.

The development of the mine itself for either mining methods follows the same procedure. First, at least three main access shafts are strategically bored into the coal bed. The accesses can be of three types: drift, slope, or shaft.[1] These types of accesses are shown in Figure 3-13. Once the main access has been constructed, two parallel main entries into the coal bed are made in the direction of the mining operation. From the main entries, a network of panel and butt entries is developed which leaves columns of unmined coal termed "pillars" which support the roof. This is the room and pillar or advance type mine.

The room and pillar mining will recover approximately 50 percent of the coal. If the ground can be allowed to subside, an additional 35 percent of the total amount of coal can be removed by mining the pillars. This is retreat mining.

Instead of the butt entries, a longwall technique can be used in which the entire side of the panel is mined at once, leaving no pillar. Longwall mining removes 80 to 85 percent of the coal in the mine.[2]

3.6.2.1a Room and pillar

Room and pillar mining is performed either by conventional methods or by continuous miners. Figure 3-14 illustrates both of these methods.[3] In conventional methods the coal seam is

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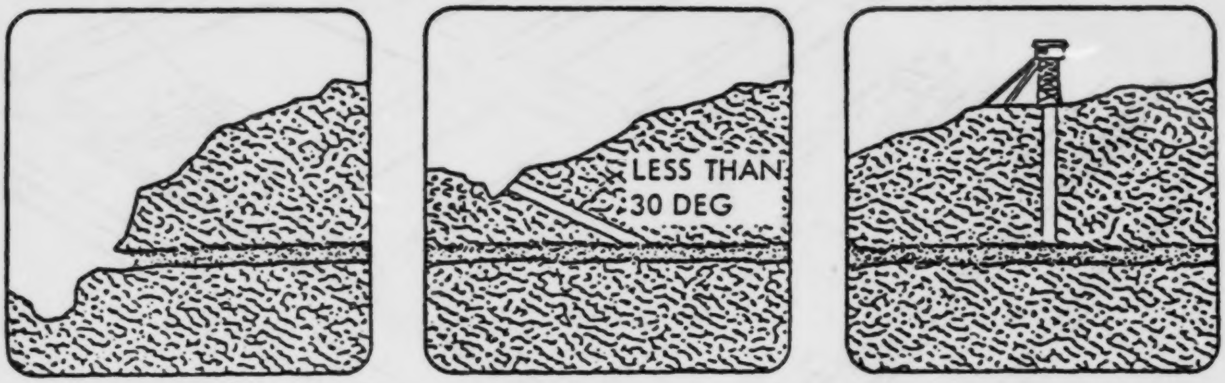
[1] TRW Systems Group. Underground Coal Mining in the United States. Research and Development Programs. Springfield, VA: National Technical Information Service. 1970. PB-193 934.

[2] *Ibid.*

[3] *Ibid.*


LESS THAN
30 DEG

DRIFT SLOPE SHAFT

Figure 3-13. The Three Types of Access Used in Underground Coal Mines

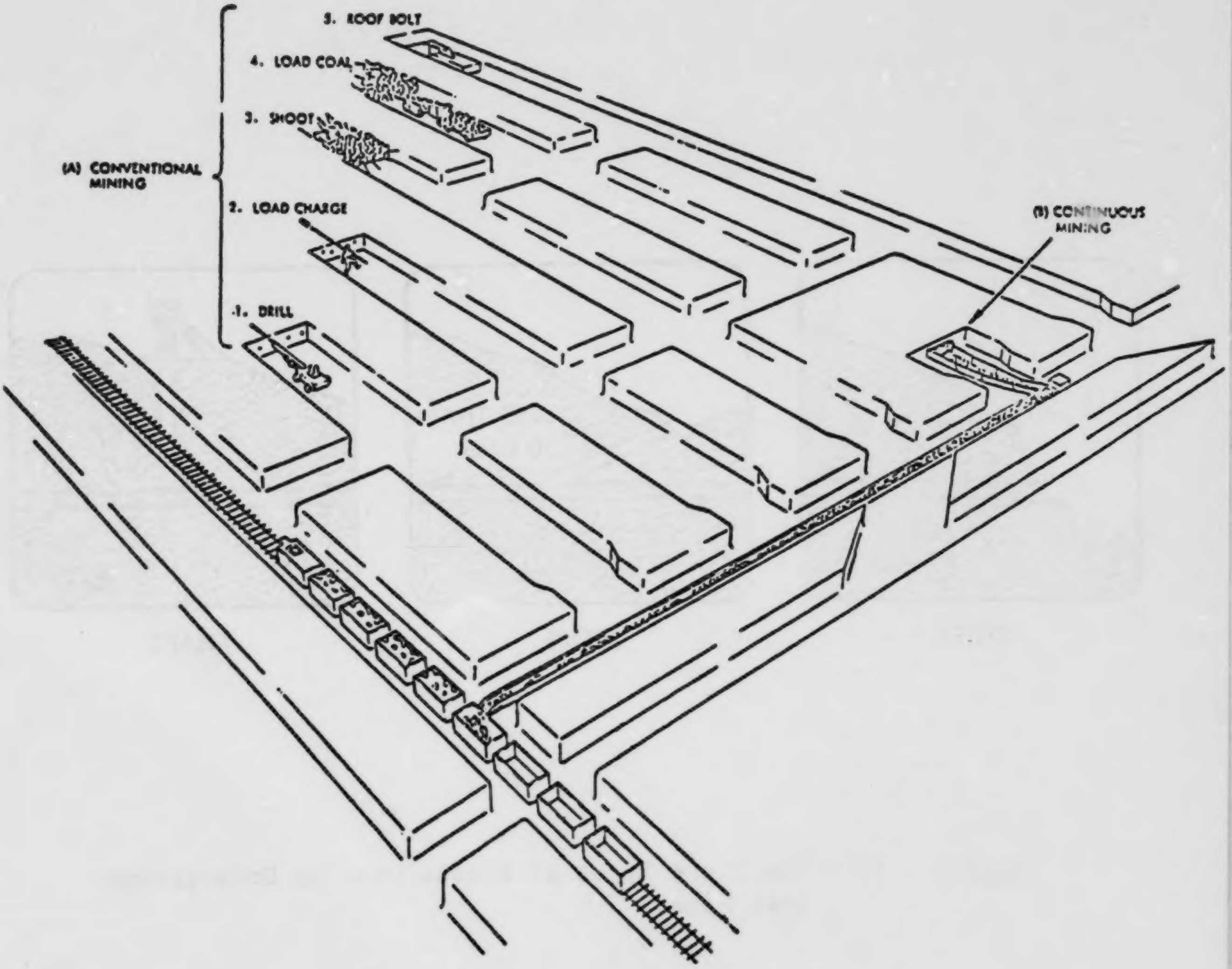

5. ROOF BOLT
4. LOAD COAL
3. SHOOT
(A) CONVENTIONAL MINING
2. LOAD CHARGE
1. DRILL
(B) CONTINUOUS MINING

Figure 3-14. Illustration of Room and Pillar Mining Using Conventional (Blasting) and Continuous Mining Techniques

blasted and then loaded by electric loaders on shuttle cars or conveyors and hauled to the main conveyor or mine rail car train. Portions of the coal are left in place to act as support pillars for the strata overlying the rooms. With the electric continuous miner, the coal is scraped from the seam and loaded directly on a conveyor or shuttle car. The coal is transported to the main conveyor or mine rail car train, and from there out of the mine.

Room size depends on the geology of the strata being mined, the governing factors being the seam thickness, the strength of the coal, and the strength of the overlying and underlying strata. In typical U. S. underground mines (which are mostly in the Eastern province), the coal and surrounding material strengths are low, and the coal seams range from two to six feet thick. As a consequence, the rooms are long and narrow, typically 10 to 20 feet wide and several hundred feet long. The rooms must be kept this small even though mechanical supports are used to increase the load-bearing capacity of the mine roof.

Roof support must be provided for the rooms excavated by either room and pillar mining method. The support system most frequently used involves drilling holes in the roof and inserting bolts equipped with either expansion heads or another fastening system.[1] Roof bolts generate compressive stresses to strenghen the roof and permit excavating larger rooms than would otherwise be possible. Recently, epoxy has been used to cement roof bolts into place.

Leaving pillars, in place to support the roof significantly decreases the portion of the coal that can be mined. On the average, about 45 to 50 percent of the coal in place is recovered in room and pillar mines. This percentage can be increased by removing additional coal when the mine is being closed down and roof support is no longer a problem. Possibly as much as 80 percent of the coal in place can eventually be recovered by the room and pillar method.[1]

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[1] Gouse, S. William, Jr. and Edward S. Rubin. A Program of Research, Development and Demonstration for Enhancing Coal Utilization to Meet National Energy Needs. Results of the Carnegie-Mellon University Workshop on Advanced Coal Technology. 1973.

As might be expected, underground mining methods are becoming more automated. Figure 3-15 reflects the growing use of machines. The continuous miner has shown the most dramatic application increase in recent years. One reason for this is that continuous mining is considerably less labor intensive than is conventional mining.

3.6.2.1b Longwall

Longwall mining has been very popular in Europe and is now gaining acceptance in the United States. The longwall process is shown in Figure 3-16. The electric longwall miner advances laterally down the panel, scraping and shearing the coal from the seam. The coal is automatically loaded on a self-advancing conveyor and transported to the main conveyor or mine rail car train. The roof is supported at the mine face by self-advancing hydraulic roof supports. As the supports are moved, the roof in the area from which the coal has been mined is allowed to collapse. The subsidence is sometimes enhanced by blasting to ensure a more controlled cave-in rate.[2]

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[1] Gouse, S. William, Hr. and Edward S. Rubin. A Program of Research, Development and Demonstration for Enhancing Coal Utilization to Meet National Energy Needs. Results of the Carregie-Mellon University Workshop on Advanced Coal Technology. 1973.

[2] TRW Systems Group. Underground Coal Mining in the United States. Research and Development Programs. Springfield, VA: National Technical Information Service. 1970. PB-193 934.

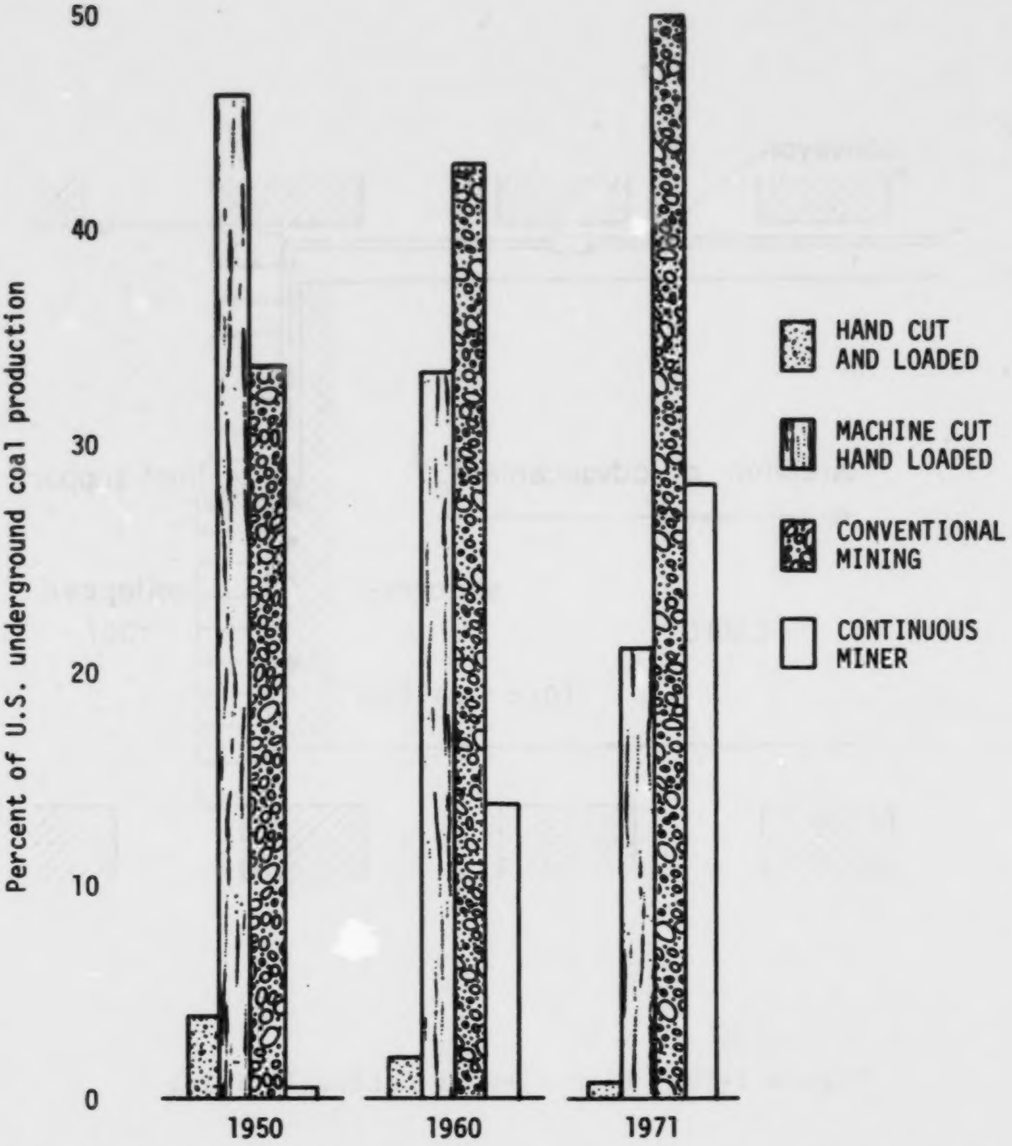

Figure 3-15. Underground Mining Methods

Source: Gouse, S. William, Jr. and Edward S. Rubin. A Program of Research, Development and Demonstration for Enhancing Coal Utilization to Meet National Energy Needs. Results of the Carnegie-Mellon University Workshop on Advanced Coal Technology, 1973.

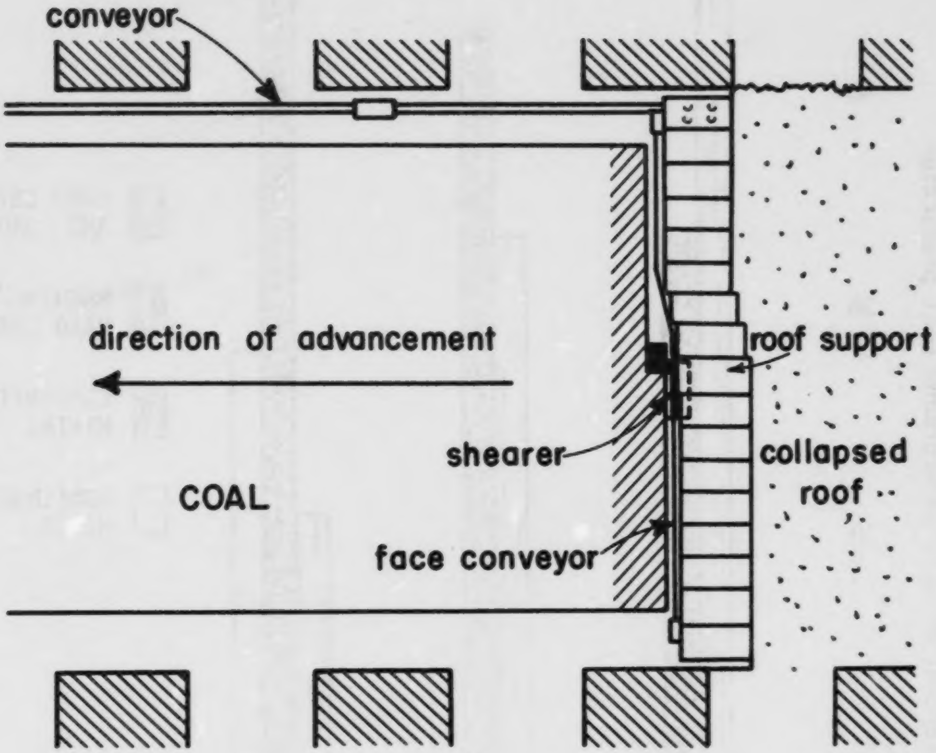
conveyor
direction of advancement
roof support
shearer
collapsed roof
COAL
face conveyor

Figure 3-16. Plan View of Longwall Mining

Source: Gouse, S. William, Jr. and Edward S. Rubin. A Program of Research, Development and Demonstration for Enhancing Coal Utilization to Meet National Energy Needs. Results of the Carnegie-Mellon University Workshop on Advanced Coal Technology, 1973.

The advantages and disadvantages of the various mining methods are given in Table 3-39. The major advantages offered by longwall mining is recovery of a higher percentage of the coal in place than is possible with the room and pillar method and its much greater safety factor. It is also less labor intensive than some of the other techniques. On the other hand, capital costs for longwall mining systems are generally greater than for room and pillar mining.[1]

3.6.2.1c Underground Mine Reclamation

The reclamation problems associated with underground mines vary somewhat from those of surface mines. A major problem is the disposal of rock and earth mined with the coal. Often the coal is cleaned at the surface to remove these materials. However, these materials cannot be simply piled up and left uncovered because they may produce toxic water runoff which is high in metals and salts dissolved from the coal by rain. One alternative is to treat the wastes with lime and dispose in sealed land fills. Materials removed to gain access to underground coal seams also require disposal in a similar manner.

Drainage, groundwater contamination, and subsidence of the surface area overlying underground mines also constitute reclamation problems. Generally, the surface will subside, limiting subsequent surface usage.

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[1] Gouse, S. William, Jr. and Edward S. Rubin. A Program of Research, Development and Demonstration for Enhancing Coal Utilization to Meet National Energy Needs. Results of the Carnegie-Mellon University Workshop on Advanced Coal Technology. 1973.

TABLE 3-39. COMPARISON OF CONVENTIONAL, CONTINUOUS, AND LONGWALL MINING

	Longwall	Continuous Room and Pillar	Conventional Room and Pillar
Advantages	• Increased production. • Eliminates some permanent roof support cost. • Cuts cost of ventiliation, storage, and rock dusting by 45%. • Provides better ventilation, roof support. • Requires less supervision. • Safer-superior method where roof conditions are poor.	• Involves fewer work cycles, less equipment, and normally produces more per man than conventional mining. • Permits more concentrated mining with fewer supervisory and ventilation problems.	• Effective in coalbeds with high hardness ratings, large partings and varying dimensions. • Produces less fine coal. • Efficient where roof and floor planes undulate.
Disadvantages	• Requires large, level straight blocks of coal free from obstructions with seam height minimum of 39". • Requires high capital investment for equipment. • Involves costly equipment moves (30-150 man-shifts to move 300 tons of equipment).	• Not effective where hardness ratings are high, partings large, floor and ceiling planes undulate, and roof conditions are poor. • Not effective where seam heights vary greatly. • Cannot be used where coal size is critical. • Provides inefficient face haulage.	• Requires numerous work cycles. • Involves larger crew and more equipment with attendant supervisory and maintenance problems. • Produces less per man. • Provides inefficient face haulage. • Not efficient where roof conditions are poor.

Partings are impure bands in coalbeds.

Source: TRW Systems Group. Underground Coal Mining in the United States. Research and Development Programs. Springfield, VA: National Technical Information Service, 1970. PB-193 934.

3.6.2.2 Input Requirements

The various inputs required for construction and operation of an underground coal mine will be discussed in the following sections. These inputs include labor, material and equipment, capital, water, land, and any outside energy. Specific assumptions regarding size and location must be made in order to quantify these input variables.

The underground mines considered in this discussion are located at the Kaiparowits Plateau in Southern Utah. The size of the operation considered is a 12 million TPY mine. A large underground mine is one that produces 3 million TPY. Therefore, for purposes of discussion, the 12 million TPY mining operation is assumed to consist of four separate mines, each producing approximately 3 million TPY.

3.6.2.2a Manpower Requirements

Construction Phase

The first phase of a mining operation is the construction phase. Although an underground mine can be built and producing within three years, this technology assessment is evaluating impacts of mines on the Kaiparowits Plateau in Southern Utah; an area for which an Environmental Impact Statement has been published.[1] In order to aline this assessment as closely with the EIS as possible, a proposed construction duration of six years is used to evaluate impacts from mine development. The estimated technical and nontechnical manpower requirements are given by man-years in Table 3-40. These estimates were made using Bechtel Corporation's Energy Supply Model; a computer simulation routine developed upon Bechtel Corporation's extensive construction experience. A shorter construction period would have little impact on the net manpower requirements of 2330 man-years.

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[1] U.S. Department of the Interior, Bureau of Land Management. Draft Environmental Impact Statement: Kaiparowits Project. 5 vols. Salt Lake City: Bureau of Land Management. 1975.

The proposed mining construction schedule for all four mines is depicted in Figures 3-17 and 3-18.

Operating Phase

Manpower requirements for underground mining of a 72-inch coal bed have been estimated by the U.S. Bureau of Mines for a 3.18 million TPY mine.[1] Total manpower requirements for a 12 million TPY mining facility consisting of four separate 3 million TPY mines is a direct scale-up of these figures. Table 3-41 presents total manpower requirements for operation of all four underground coal mines.

3.6.2.2b Materials and Equipment

The Bureau of Mines has estimated capital costs for operation of various underground coal mines.[2] In so doing, the Bureau of Mines itemized and priced out the major pieces of equipment required for operation of a 3.18 MM TPY underground mine. Table 3-42 presents this listing but the numbers have been adjusted to reflect operation of a 12 million TPY mine - essentially four 3 million TPY facilities operating separately.

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[1] Katell, Sidney, E.L. Hemingway, and L.H. Berkshire. Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines: Mines With Annual Production of 1.03 to 3.09 Million Tons From a 48 Inch Coal Bed. Bureau of Mines Information Circular 8641. Morgantown, WV: Bureau of Mines. 1975.

[2] *Ibid.*

TABLE 3-40. SCHEDULE OF MANPOWER RESOURCES REQUIRED FOR CONSTRUCTION OF A 12 MM TPY UNDERGROUND COAL MINE

Discipline	Manpower (man-years) Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6
Civil Engineers	1	12	21	33	21	5
Electrical Engineers	1	7	12	20	12	3
Mechanical Engineers	1	11	19	29	18	4
Mining Engineers	0	5	9	14	9	2
Other Engineers	1	10	17	26	16	4
TOTAL ENGINEERS	4	45	78	123	76	17
TOTAL DESIGNERS + DRAFTSMEN	2	19	33	52	32	7
TOTAL SUPERVISORS + MANAGERS	0	5	9	14	9	2
TOTAL TECHNICAL	6	69	119	188	116	26
TOTAL NON-TECH (NON-MANUAL)	1	8	13	20	15	3
Pipefitters	1	19	31	50	37	6
Electricians	1	21	35	56	41	7
Iron Workers	1	13	21	34	25	4
Carpenters	1	10	16	26	19	3
Operating Engineers	3	40	66	106	77	14
Other Major Skills	4	65	106	172	125	22
Total Craftsmen	11	167	274	444	323	57
Total Teamsters + Laborers	4	61	101	164	119	21
GRAND TOTAL	22	305	507	816	573	107

Source: Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

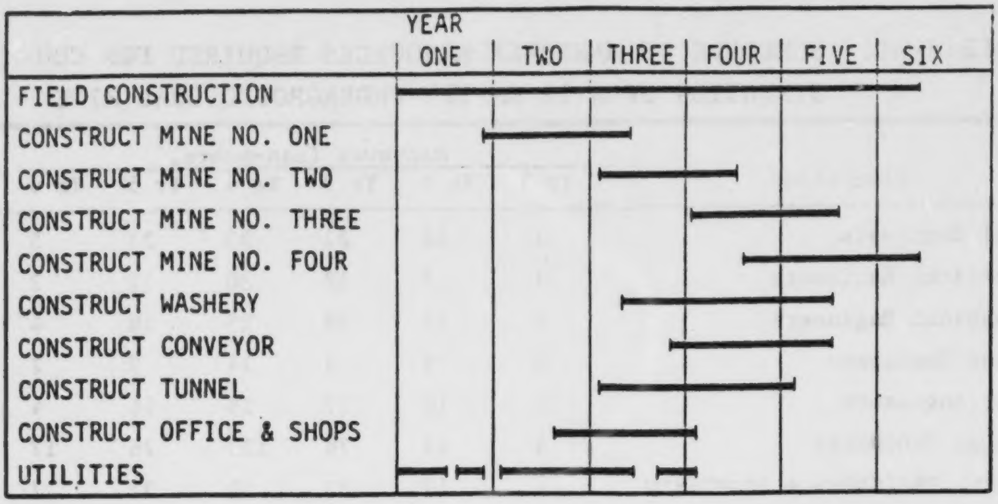
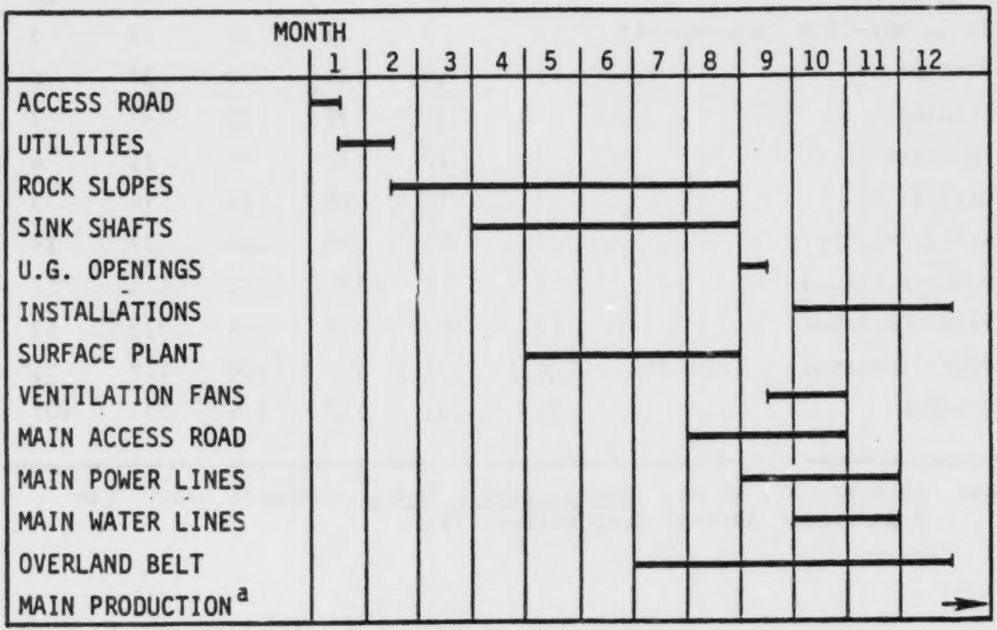


Figure 3-17. Overall Mining Project Construction Schedule



[a] Phased into full production of three million tons per year as equipment is assembled and installed underground.

Figure 3-18. Individual Mine Development Schedule

Source: U.S. Department of the Interior, Bureau of Land Management. Final Environmental Impact Statement: Kaiparowits Project, 5 vols. Salt Lake City: Bureau of Land Management, 1975. p. I-207.

TABLE 3-41. TOTAL MANPOWER REQUIREMENTS FOR OPERATION OF FOUR UNDERGROUND COAL MINES (NET PRODUCTION 12 MILLION TPY)

Personnel	Total
Underground:	
Continuous miner operation	158
Loading machine operation	158
Machine operator helper	158
Shuttle car operator	317
Roof bolter	317
Bratticeman	158
Utility man	158
Mechanic (section)	158
Supply motorman	45
Beltman	102
Trackman	45
Wireman	45
Mason (precision)	68
Pumper	11
Utility crew	91
Roving mechanic	45
Fireboss (union)	15
Outside:	
Lampman	11
Front-end loader operator	11
Shop mechanic	45
Salary:	
Superintendent	4
General mine foreman	4
Assistant mine foreman	11
Section foreman	158
Maintenance superintendent	4
General shop foreman	4
Mine maintenance foreman	11
Chief mine engineer	4
Draftsman	4
Survey crew	11
Safety director	4
Safety inspector	11
Dust sampler	11
Office manager	4
Timekeeper and bookkeeper	4
Purchasing supervisor	4
Warehouseman	15
TOTAL LABOR AND SUPERVISION	2,384

Source: Katell, Sidney, E.L. Hemingway, and L.H. Berkshire. *Basic Estimated Capital Investment and Operating Cost for Underground Bituminous Coal Mines*. Information Circular 8682, Morgantow, WV: Bureau of Mines, 1975.

TABLE 3-42. MAJOR EQUIPMENT SUMMARY, FOUR MINES TOTALING 12 MILLION TPY

Item	Quantity
Continuous miner	64
Loading machine	64
Shuttle car	129
Roof bolter	64
Ratia feeder	64
Auxiliary fan	64
Mantrip Jeep	64
Mechanic Jeep	23
Personnel Jeep	30
Trickle rock duster	64
Triple duty rock duster	50
Supply motor	23
Supply car	265
42-inch rope-type mainline belt conveyor	34,000 ft
36-inch rope-type secondary and panel belts	136,000 ft
Mainline belt power center (300 kV-A)	23
Section belt power center (150 kV-A)	53
Section power center (1,000 kV-A)	64
Section rectifier (200 kW)	64
Section switch house	64
Sectionalizing switch house	38
HV cable (300 MCM AL)	61,000 ft
PLM coupler	68
Section cable and coupler	--
Rectifier for truck haulage	11
Trolley wire	193,000 ft
Track (60-lb)	193,000 ft
Fresh water line	193,000 ft

(Continued)

TABLE 3-42. (Continued)

Item	Quantity
Pumps and lines	--
Telephone (page phones)	--
Conveyor fire protection	--
Automatic controls and alarms	--
Scoop tractor	64
Battery charger	64
All service mask	136
Breathing apparatus	136
Self rescuer	2,462
Stretcher set	76
Safety light	1,137
Methanometer	1,137
Fire chemical car	38
Lamp (including accessories)	2,462
Dust sampler	190
Concrete portal	19
Bulk rock dust facility	4
Substation and distribution	4
Bathhouse, office, and lamp house	4
Shop and warehouse	4
Powder and cap house	4
Front-end loader	4
Forklift	4
Bulldozer	4
Utility truck	7
Pickup truck	7
Oil storage	4
Water tank	4
Supply yard	4

Source: Katell, Sidney and E.L. Hemingway. Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines: Mines with Annual Production of 1.03 to 3.09 Million Tons from a 48-Inch Coal Bed. Bureau of Mines Information Circular 8641, Morgantown, WV: Bureau of Mines, 1975.

Bechtel Corporation[1] has estimated the material required for construction of a 12 million TPY mine based on previous construction experience. Their estimates indicate that 92,000 tons of ready mixed concrete, 4600 tons of piping, 6000 tons of structural steel, and 6800 tons of reinforcing bars will be required to build the underground mine.

3.6.2.2c Economics

The capital investment and annual operating cost for a 3 million TPY underground coal mine are presented in Tables 3-43 and 3-44. These were developed by the Bureau of Mines based on 1974 costs.[2] As summarized in Table 3-45, the total capital investment for four such mines producing a net 12 million TPY is $308 million and the total annual operating cost is $100 million. The resulting coal selling price is $11.68/ton in 1974 dollars. By 1976 these costs had risen to approximately $20/ton.[3]

3.6.2.2d Water Requirements

The only process water requirements of the mining operations considered here would consist of the water used for dust control in the crushing plant and along haulage roads. All of the water required to satisfy these demands is assumed to be available in the form of reclaimed water collected as mine drainage. For this reason, no water requirements are acknowledged for an underground mine.

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[1] Carasso, M., *et al*. Energy Supply Model. Computer Tape. San Francisco: Techtel Corporation. 1975.

[2] Katell, Sidney, E.L. Hemingway, and L.H. Berkshire. Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines: Mines With Annual Production of 1.06 to 4.99 Million Tons From a 72-Inch Coalbed. Bureau of Mines Information Circular 8682. Morgantown, WV: Bureau of Mines. 1975. p. 5.

[3] Nielson, George F., ed. 1977 Keystone Coal Industry Manual. New York, New York: McGraw-Hill Mining Publication. 1977. p. 545.

TABLE 3-43. ESTIMATED WORKING CAPITAL AND TOTAL CAPITAL INVESTMENT (3 MILLION TPY MINE, 1974)

Item		Cost ($ million)
Estimated working capital:		
Direct labor	3 months	1.8
Operating supplies	3 months	1.4
Payroll overhead	3 months	.7
Indirect cost	4 months	.6
Fixed cost	0.5 percent of insurance base	.2
Spare parts		.6
Miscellaneous		.1
Total working capital		5.4
Total estimated capital investment:		
Total mine cost (insurance, tax base)		44.7
Interest during development		2.0
Subtotal		46.7
Working Capital		5.4
Estimated capital investment		52.1
Estimated deferred capital investment		24.9
Total capital investment and deferred investment		77.0

Source: Katell, Sidney, E.L. Hemingway, and L.H. Berkshire. Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines: Mines with Annual Production of 1.06 to 4.99 Million Tons From a 72-Inch Coalbed. Bureau of Mines Information Circular 8682, Morgantown WV: Bureau of Mines, 1975. p. 5.

TABLE 3-44. ESTIMATED ANNUAL PRODUCTION COST (3 MILLION TPY MINE, 1974)

Item	Annual Cost ($ Million)	Cost per ton ($/ton)
Direct cost:		
Production:		
Labor	5.34	1.78
Supervision	.87	.29
	6.28	2.07
Maintenance:		
Labor	.75	.25
Supervision	.09	.03
	.84	.28
Operating supplies:		
Mining machine parts	1.89	.63
Lubrication and hydraulic oil	.75	.25
Roof bolts and timber	.93	.31
Rock dust	.39	.13
Ventilation	.57	.19
Bits	.36	.12
Cables	.18	.06
Miscellaneous	.45	.15
	5.52	1.84
Power	.96	.32
Water		
Payroll overhead (40 percent of payroll)	2.82	.94
Union welfare[a]	3.06	1.02
Indirect cost:		
15 percent of labor, supervision, and supplies	1.89	.63
Fixed cost:		
Taxes and insurance, 2 percent of mine cost	.90	.30
Depreciation	2.34	.78
	3.24	1.08
TOTAL	24.54	8.18

[a] Effective Dec. 6, 1974, under the Bituminous Wage Agreement of 1974.

Source: Katell, Sidney, E.L. Hemingway, and L.H. Berkshire. *Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines: Mines with Annual Production of 1.06 to 4.99 Million Tons From a 72-Inch Coalbed*. Bureau of Mines Information Circular 8682, Morgantown WV: Bureau of Mines, 1975. p. 5.

TABLE 3-45. CAPITAL AND INVESTMENT COST FOR UNDERGROUND COAL MINING (1974)

Item	Cost	
	1 mine	4 mines
Production (million tons/year)	3	12
Initial Capital Investment ($ million)	52	208
Deferred Capital Investment ($ million)	25	100
Total Capital Investment ($ million)	77	308
Total Capital Investment/Annual Production ($/ton)	25.48	25.48
Annual Operating Cost ($ million)	25	100
($/ton)	8.18	8.18
Required Selling Price @15% DFC ($/ton)	11.63	11.63

Source: Katell, Sidney, E.L. Hemingway, and L.H. Berkshire. Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines: Mines with Annual Production of 1.06 to 4.99 Million Tons from a 72-Inch Coalbed. Bureau of Mines Information Circular 8682, Morgantown, WV: Bureau of Mines, 1975. p. 5.

3.6.2.2e Land Requirements

In addition to the mine itself, land requirements for underground mining operations include the areas occupied by coal processing and loading facilities. Estimated total land requirements for typical western and midwestern mining operations are summarized as follows:

Mine Site:	
Active Working Area (acres)	322
Land Being Reclaimed (acres)	2,350
Haulage Road (acres)	5
Processing and Loading (acres)	75
TOTAL ACRES	2,752

The land area designated as the active working area was assumed to be equal to the land disturbed or undermined in 100 days of mining activity. Reclamation land requirements were determined by assuming that two years are required to allow for subsidence prior to the start of reclamation activities. The haulage road requirements were taken from Hittman.[1] The 75 acres allocated to the aboveground processing facilities (crushing, loading, and water treatment) was an assumed figure.

At any given time approximately 2800 acres will be in use by the mining operation. Throughout the 30 year life of the mine, a total of 36,000 acres will have been occupied by the mine. By far the largest portion of this land requirement can be reclaimed and returned to other production uses.

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[1] Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use. Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, MD: Hittman Associates, Inc. 1974 and 1975.

3.6.2.2f Ancillary Energy

Ancillary energy requirements for a 3.18 million TPY underground coal mine are presented in Table 3-46. These estimates were developed by the Bureau of Mines based on an Appalachian room and pillar mine.[1] A single 3 million TPY mine would require approximately 246,000 kwh and four such mines producing 12 million TPY would require approximately 960,000 kwh/d. Assuming a 33 percent power plant efficiency, the net energy requirement for the production of 12 million TPY of coal is 3.5 x 10^{12} Btu/year.

3.6.2.3 Outputs

Outputs from underground mining activities depend on the size of the mine which in turn depends on the demand for energy from that particular mine. Outputs will also depend on the type of underground mining method employed. Since continuous room and pillar mining is by far the most prevalent form of underground mining in the U.S., accounting for over 62 percent of the total underground bituminous and lignite production, it will be the extraction method for which the emissions and other outputs will be presented in this section.

The underground mines considered in this discussion are located at the Kaiparowits Plateau in Southern Utah. The size of the operation considered is a 12 million TPY mining operation consisting of four 3 million TPY units.

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[1] Katell, Sidney, E. L. Hemingway, and L. H. Berkshire. Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines: Mines With Annual Production of 1.06 to 4.99 Million Tons From a 72-Inch Coalbed. Bureau of Mines Information Circular 8682. Morgantown, WV: Bureau of Mines. 1975. p. 28.

TABLE 3-46. POWER REQUIREMENTS FOR A 3 MILLION TPY UNDERGROUND COAL MINE

Number of units	Operation	Hp per unit	Hp, total load	Hr per day, full load	KW, total load	Total kW-hr requirement
14	Continuous miner	600	8,400	15	6,266	93,900
14	Loading machine	160	2,240	15	1,671	25,065
28	Shuttle car	135	3,780	15	2,820	42,300
14	Roof bolter	50	700	18	522	9,396
14	Ratio feeder	125	1,750	15	1,305	19,575
14	Auxiliary fan	30	420	18	313	5,634
14	Mantrip Jeep	15	210	6	156	936
6	Mechanic Jeep	15	90	15	67	1,005
8	Personnel Jeep	7.5	60	15	45	675
14	Rock duster	30	420	12	313	3,756
6	Supply motor	80	480	12	358	4,296
3	42-inch conveyor	200	600	15	447	6,705
12	36-inch conveyor	150	750	15	560	8,400
1	Ventilation fan		500	24	373	8,952
	Extra for pumps, tools, lights, etc.		500	10	373	3,730
	TOTAL					234,415

Source: Katell, Sidney, E.L. Hemingway, and L.H. Berkshire. Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines: Mines with Annual Production of 1.06 to 4.99 Million Tons from a 72-Inch Coalbed. Bureau of Mines Information Circular 8682, Morgantown, WV: Bureau of Mines, 1975. p. 28.

3.6.2.3a Air Emissions

The vented air from the mine is calculated to have a flow of one million cubic feet per minute. This value is based on a design criteria set to keep the methane concentrations below 0.1 vol percent of the air in the mine.[1] The methane production rate in the underground mine module is 200 cubic feet per ton of coal mined.[2] Therefore, the methane emission rate is calculated as 3000 lbs/hr per mine or 12,000 lbs/hr for the total complex. The ventilation air in the mine is supplied by an induced draft system equipped with a large electric exhaust fan. The ventilated air and methane are exhausted to the atmosphere with no further treating.

Particulate emission levels in the mine are maintained at the federal standard of 2.0 mg per cubic meter by the ventilation system.[3] Particulate emissions from the continuous miners at the mine face may reach levels as high as 40 mg per cubic meter.[4] The particulate matter generated by the continuous miners are, however, controlled by air scrubbing systems equipped on the miners. The air scrubbing systems are Venturi-type scrubbers with mini-cyclones and water spraying apparatus.[5] Ventilation air rates at the mine face are maintained between 6,000 and 20,000 scfm to dilute any methane that is produced from the mining operation.[1] Fugitive dust within the mine also results from primary crushing. The module primary crusher has a dust emission factor of 0.1 lb of suspended solids per ton crushed.[2] This factor is assumed to be reduced 80 percent by use of water sprays. The final quantity of suspended dust is diluted in the ventilation air and exits the mine in the ventilation system.

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[1] TRW Systems Group. Underground Coal Mining in the United States. Research and Development Programs. Springfield, VA: National Technical Information Service. 1970. PB-193 934.

[2] "Degasification of Coalbeds - A Commercial Source of Pipeline Gas." A.G.A. Monthly 56 (1), 4 (1974).

[3] Hill, Robert W. "Dust Control With Collectors on Continuous Miners." Mining Cong. J. 60 (7), 46 (1974).

[4] TRW Systems Group, *op.cit.*

[5] Hill, Robert W., *op.cit.*

Since all equipment is assumed to be electric, the major source of atmospheric emissions is the exhaust air from the ventilating system. For the example four underground coal mines, 700 lbs of particulates and 288,000 lbs of hydrocarbons are emitted each day.

3.6.2.3b Water Effluents

Mine drainage and surface runoff is assumed to be collected, treated, and used to satisfy mine site water demands: dust supression and reclamation. However, mine drainage and surface runoff can exceed mine site water demands. In these instances, mine effluent water must be held in settling ponds for suspended solids removal. Following treatment, the mine drainage is suitable for use in coal processing facilities, power plants, or release into water systems. If flows are small enough and no reuse alternatives are available, mine drainage can be disposed in evaporation ponds.

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[1] TRW Systems Group. Underground Coal Mining in the United States. Research and Development Programs. Springfield, VA: National Technical Information Service. 1970. PB-193 934.

[2] Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. 2nd ed., with supplements. Research Triangle Park, NC: Environmental Protection Agency. 1973.

3.6.2.3c Solid Wastes

Mine disposal of underground mining refuse is generally not practiced. According to Hittman,[1] solid wastes are produced in an Illinois underground mining operation at a rate of 99.3 tons per 10^{12} Btu coal extracted. Therefore, the mines in this discussion will be assumed to produce 78 tons of solid wastes per day which must be disposed of on the surface. However, this material cannot be simply piled up and left uncovered, because it may produce toxic water runoff when dissolved by rain. One alternative is to dispose of the wastes in sealed land fills and valley fills.

3.6.2.3d Noise Pollution

The only noise that will affect the surrounding environment is noise associated with the surface equipment, such as truck loading, railcar loading, conveyor transportation, etc. Due to the remoteness of western coal mines, these noise effects are generally negligible for the public.

3.6.2.3e Occupational Health and Safety

Mine safety, a continuing problem, is more critical in underground than in surface mining. In surface mines, safety problems are much the same as those associated with any activity involving heavy equipment and the use of explosives. In underground mines, ventilation, methane control, general fire and explosion control, and roof support are additional problems. Despite these formidable safety problems, underground mine safety has been improving since the Bureau of Mines began keeping records in

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[1] Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, MD: Hittman Associates, Inc. 1974 and 1975.

1910 and, as Figure 3-19 indicates, fatalities have decreased since that time.

Mines are usually ventilated by positively managing airflow patterns throughout the mine. This may include erecting temporary partitions, establishing airwall barriers, and installing fans to circulate air. Ventilation systems typically include several techniques, together with dust collectors and monitoring equipment.

Methane has always been a problem in underground mines. Most current attempts to deal with this problem use conventional ventilation methods. However, degasification (including drilling holes to drain methane pockets or introducing gases which have a higher affinity for methane than does coal) is now receiving R&D attention.[1] Although at least one large coal company is pursuing seismic technologies to locate methane pockets, it is not clear whether this is an operational procedure in all of the company's underground mines (Interview with industry engineer, June 1974).

In addition to methane/drainage, fire and explosion control includes installing fire quenching systems, dust suppressors, explosion and fire barriers, inflatable seals, and monitoring systems. Rigid inspection, testing, and approval procedures have helped make mine equipment safer. Based on mine safety records, Hittman Associates have also estimated that yearly injuries in a 12 million TPY mine will likely total 370 and there will be approximately 210,000 man-days lost.[2]

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[1] Gouse, S. William, Jr., and Edward S. Rubin. A Program of Research, Development Demonstration for Enhancing Coal Utilization to Meet National Energy Needs, Results of the Carnegie-Mellon University Workshop on Advanced Coal Technology. 1973.

[2] Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use. Final Report: Vol I, 1974, Vol II, 1975. Columbia, MD: Hittman Associates, Inc. 1974, 1975.

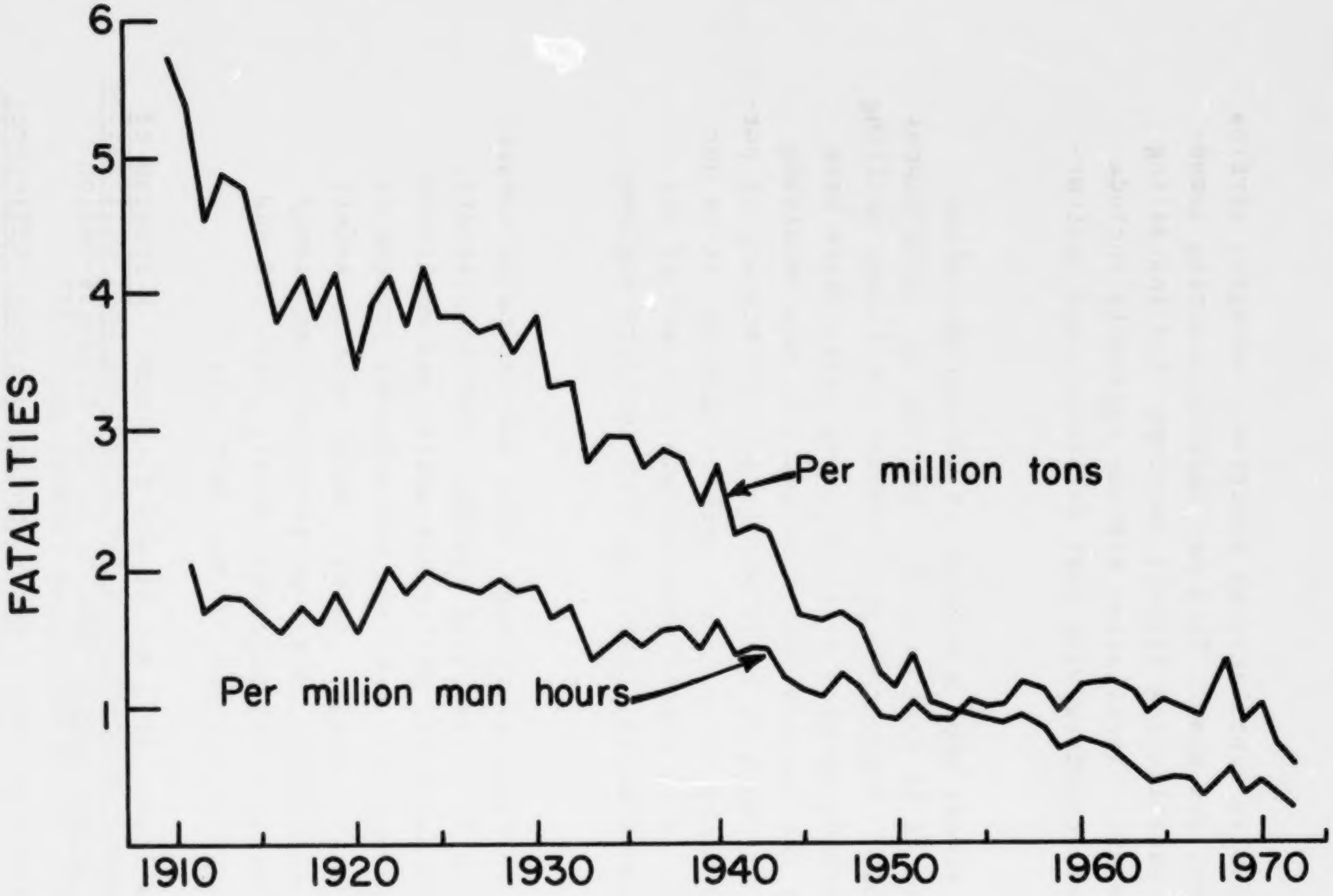

Figure 3-19. Underground Mine Fatalities

Source: Gouse, S. William, Jr., and Edward S. Rubin. A Program of Research, Development and Demonstration for Enhancing Coal Utilization to Meet National Energy Needs. Results of the Carnegie-Mellon University Workshop on Advanced Coal Technology, 1973.

Table 3-47 presents a summary of the direct impacts from a 12 MM TPY underground coal mine located at the Kaiparowits scenario.

3.6.3 Social Controls

Coal mining and reclamation are subject to regulation by both the federal and state governments. Both have developed laws, regulations, rules, and policies that either directly or indirectly affect the deployment of mining technologies. These control how lands are obtained for mining and procedures to ensure safety and environmental protection and reclamation. These are described in several jurisdictional levels in the following sections.

3.6.3.1 Obtaining Minable Land (Leasing)

Following exploration, or when deposits are known to exist, a number of procedures are followed to obtain rights to the minerals so that mining can begin. As described in the general social control chapter, if mineral rights are separated from surface rights, which is commonly the case, the mineral owner may sell or lease his right to remove the coal. If the mineral rights have not yet been severed from the surface, the surface owner would still own the rights to minerals and could sell or lease his rights to a portion or all of the minerals. For example, the owner may sell or lease only the right to coal. Generally, coal developers have acquired rights by leasing rather than outright purchase from owners. The general situation as described above, is applicable to surface and mineral ownership whether federal, state, Indian or private. However, some variations exist when either the federal or state governments owen mineral or surface rights.

TABLE 3-47. SUMMARY OF IMPACTS ASSOCIATED WITH A 12 MM TPY UNDERGROUND COAL MINE AT KAIPAROWITS

Inputs	
Manpower	
• construction	2,330 man-years
• operating	2,384 men
Materials and Equipment	
• continuous miners	64
• loading machines	64
• ready mixed concrete	92,000 tons
• structural steel	6,000 tons
• reinforcing bars	6,800 tons
• piping	4,600 tons
Economics[a]	
• capital costs	$308 million
• operating costs	$100 million
Water	None
Land	
• at any given time	2,750 acres
• 30 year total	36,000 acres
Ancillary Energy	3.5×10^{12} Btu/yr
Outputs	
Air Emissions	
• particulates	0.35 ton/day
• hydrocarbons	144 ton/day
Water Effluents	Highly site dependent
Solid Wastes	78 tons/day
Noise	Insignificant
Occupational Health and Safety	
• fatalaties	7.2 deaths/yr
• injuries	370 injuries/yr
• lost man-days	210,000 man-days

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[a] 1974 dollars

3.6.3.1a Federal Lands[1]

Policies regarding the development of coal on federal lands have changed substantially over the past 200 years. (See the summary of significant legislation in Table 3-48.) Coal development was suspended in 1973 when the Secretary of the Interior announced that the coal prospecting and leasing program was temporarily suspended. Following the suspension, preference right leasing was eliminated, and all leasing is now competitive. The federal government has developed three categories of lands, and to some extent the jurisdiction over coal development on these lands vary. (See Table 3-49.) The procedures for leasing or licensing these lands are summarized in Table 3-50.[1]

3.6.3.1b Indian Lands

Procedures for acquiring Indian lands are generally the same as those for federal lands, although Indian authorities do have veto power over leasing decisions. Indian lands are administered in a cooperative trusteeship. Although Indian lands are not an integral part of the public domain, Indians do not have complete legal title.

There are three principal categories of Indian lands: allotted, where title has been partially transferred to individial Indian landowners; tribal, where the lands are collectively owned, and ceded, where surface rights are privately held and mineral rights are held by a tribe.

The Bureau of Indian Affairs (BIA) acts as a trustee, both for individual Indians and tribes. The stated goal is to protect Indian interests from overzealous government policies and to

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[1] Federal leasing procedures are currently in a state of flux. See U.S. Department of Interior, Coal Leasing Programmatic Impact Statement, 1975.

TABLE 3-48. SUMMARY OF SIGNIFICANT PUBLIC LANDS MINERALS OWNERSHIP LEGISLATION

Year	Act	Significant Points
1785	Land Ordinance	Lands view as a source of government revenue.
1841	The General Preemption Act (5 Stat. 453)	Encouraged land development.
1862	Homestead Law (12 Stat. 392)	Encouraged land development.
1866	The Mining Act (14 Stat. 251)	Public lands declared free and open, revenue raising abandoned.
1872	General Mining Law (17 Stat. 91)	System for claims and encouragement of mineral exploration and development.
1873	The Coal Lands Act (17 Stat. 607)	Lands containing coal could be sold to private owners.
1910	Pickett Act (36 Stat. 847)	Gives President discretionary authority to withdraw public lands from sale. Reserves public lands for public use.
1920	Minerals Leasing Act (41 Stat. 847)	Returned to early policy of developing public lands, but federal givernment retains title.
1947	Acquired Lands Mineral Leasing Act (61 Stat. 913)	Extends leasing system to federal lands acquired for special purposes.
1954	Multiple Minerals Development Act (68 Stat. 708)	Enable mining for other minerals while reserving leasing rights for coal.
1955	Multiple Surface Use Act (69 Stat. 708)	Encourages multiple mineral development, especially sand and gravel on public lands subject to mining.
1970	Mining and Minerals Policy Act (84 Stat. 1876),	Established guidelines for a sound domestic minerals industry, orderly development, and research and development.
1975	Federal Coal Leasing Amendments Act (90 Stat. 1083)	Environmental impact considered. Terms and conditions set, land use plans required.

TABLE 3-49. SUMMARY OF FEDERAL LAND CATEGORIES AND JURISDICTION

Land Category	Predominant Agency
Public Domain: Lands subject to disposal or sale under the general land laws of the U.S. but not including either reserved lands, withdrawn lands, or coastal lands below the low water mark.	BLM
Reserved: Lands that have been set apart by the congressional or executive branches for a special public use such as national forests, Indian and military reservations, etc.	BLM BIA DOD DOA
Withdrawn: Lands temporarily removed from the public domain by special legislation usually for conservation purposes.	BLM
Acquired: Lands that were never a part of the public domain or that were once public but owned either privately or by a state government when acquired or reacquired by the federal government.	BLM

TABLE 3-50. SUMMARY OF LEASING AND LICENSING FEATURES FOR FEDERAL AND INDIAN LANDS

Method	Period	Acreage	Rental or Royalty	Procedures
Preference* Lease (non competitive)	Indeterminate	46,080 acres per state	Rent and royalty set by USGS	1. Initiated by private individuals or BLM 2. Documentation of workable deposits reviewed by BLM and USGS 3. EIS process if applicable 4. Lease sold 5. Diligent development required
Competitive Lease	Indeterminate	46,080 acres per state	USGS sets minimum, amount competitively determined	1. Federal coal lands review by BLM 2. Initiated by private individuals or by BLM 3. Nominations (private) 4. BLM nomination reviewed by USGS 5. EIS if applicable prepared by BLM 6. Special lease terms and conditions prepared by BLM 7. Lease sale 8. Diligent development required
Indian Lands	Ten Years	2,560 acres	Flexible, based on comparisons with local markets	1. Initiated by tribes to private individuals 2. Nominations approved by Indians and BIA 3. EIS process if applicable 4. Lease sale

*New leases (under this category) are no longer made. However, preference lease features are applicable to existing preference leases.

provide assistance and service in granting permits and making leases. Both the federal government and the Indian tribes have veto power over a lease.

3.6.3.1c State Lands

Most states have constitutional provisions authorizing the sale of state-owned lands. However, there has been a trend toward reserving mineral rights to the states. States usually have a goal of effecting a policy "to promote the discovery and development of the mineral resources of the state for the benefit of the public through a system of licensing on a royalty basis.[1] By 1970, most of the western states had enacted legislation providing for leasing state-owned lands. These lands include:

1) Public lands that were still under the state's sovereign power at the time of admission to the Union;

2) Land grants to the state from the federal government at the time the state was created;

3) Lands in the beds of rivers and streams that were navigable at the time the state was created; and

4) Lands acquired by the state, such as lands confiscated for nonpayment of taxes.[2]

The states have only limited control over land grants since the Congress specified the purposes for which they could be used. In addition, many of the states sold the lands transferred to them by the federal government without reserving the mineral rights to themselves.

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[1] Verity, Victor, John Lacy, and Joseph Geraud. "Mineral Laws of State and Government Bodies." American Law of Mining. Vol. II, Title XII. pp. 627-638.

[2] *Ibid.*

In all western states, responsibility for managing the leasing state lands and minerals is located in a single state agency. The administrative head of the agency may be authorized to accept or reject prospecting and lease applications. It is not unusual, however, for leasing approval to require the consent of more than one state agency.

If state lands are known to contain commercially valuable coal deposits, they will usually be leased competitively. If it is unknown whether the lands contain commercially valuable deposits, systems range from first-come-first-served to competitive bidding.

In the western states leases are commonly for an initial term of up to 10 years, with a preferential right for renewal. However, some states offer an initial term of as little as five years while others offer as many as 20. When the initial term is short, the lease usually remains in force as long as the mine continues to produce in paying quantities or as long as the development operation is continued in good faith.

Rental rates for state mineral leases are usually fixed, whereas royalties are usually calculated as a percentage of the value of production. Some states require rent only, others require both rent and royalties, and some require only royalties.

At least two states have statutes requiring at least some competitive leasing of state coal lands (Montana and Utah), although in Utah the requirement is only on newly acquired lands of the state. It is possible for the state leasing agency in the remainder of the states to require competitive leasing in their own regulations. At least two states give a preference (by statute) to the prospector or permit holder (Arizona, New Mexico).

Tables 3-51 through 3-58 summarize state leasing features. The second item on each table, Requirements, is usually left blank indicating an application with a minimum of information (applicant's name, address, and location of the land involved). If there are requirements beyond the minimum above, the statute will be listed in that category.

3.6.3.1d Private Lands

Contracts for developing coal on privately owned lands are of three principal types: sale, lease, and license. Leases differ from sale primarily by being limited to a fixed time period; but a lease does effectively transfer ownership of the resource for the time period specified in the contact. Licenses do not, and they may be revoked.

State laws govern all three types of contracts. While there is a great deal of diversity among the states, there also have been some similarities in the content of private coal contracts, and the most common type of contract is the lease. In this arrangement most state laws are similar in terms of:

1) The ways in which rights are transferred and defined, particularly in the granting clause that describes the coal to be mined;

2) The definition of limitations in the lease, such as the duration, which is almost always for a fixed term;

3) Express covenants outlining requirements for development and marketing, including the lessee's duty to mine "merchantable coal" in a "proper manner"; and

TABLE 3-51. ARIZONA COAL LEASE FEATURES[a]

Item	Statutes	Summary
1. Agency	§ 27-254	State Land Department, State Land Commissioner.
2. Requirements	§ 27-254	1. Discovery under exploration permit. 2. Proof of valuable mineral deposit.
3. Fees		
4. Rental	§ 27-234	$15.00 per year for each 20 acres.
5. Royalty	§ 27-234	50 percent of net value of production.
6. Duration	§ 27-235	20 years, with renewal of successive 20 year terms.
7. Bond		
8. Other Information		

[a] Arizona Revised Statutes Annotated, 1956

TABLE 3-52. COLORADO COAL LEASE FEATURES[a]

Item	Statutes	Summary
1. Agency	§ 36-1-113	State Board of Land Commissioners.
2. Requirements		
3. Fees	§ 36-1-112	Application - 50¢ Lease - $1.00 Lease service fee - $5.00
4. Rental	§ 36-1-114	Board may adjust rentals to get maximum revenue
5. Royalty	§ 36-1-139	15¢ per ton
6. Duration		
7. Bond		
8. Other	§ 34-32-109	See Section 1.6.2.3.2 for open mine permit if required

[a] Colorado Revised Statutes, 1973.

TABLE 3-53. MONTANA COAL LEASE FEATURES[a]

Item	Statutes	Summary
1. Agency	§ 81-501	State Board of Land Commissioners
2. Requirements		
3. Fees		
4. Rental	§ 81-503	Rent set by board, but not less than $2.00 per acre.
5. Royalty	§ 81-503	Set by board, but not less than 10 percent
6. Duration	§ 81-502	Ten years, renewable every five years
7. Bond		
8. Other	§ 50-10 § 50-16 § 69-33	See Section 1.6.2.3.2 for Strip and Underground Mining Act, Mine Siting Act, for geophysical exploration permit.
	§ 81-501	This leasing or exploration agreement must be executed by competitive bid to return at least the fair market value.
	§ 81-2612	If there is a conflict between coal, oil, gas, or geothermal developers on state lands, the first issued lease has priority, but the board may amend to fit the situation.

[a] Revised Codes of Montana, 1947; this is also the procedure for coal exploration in Montana.

TABLE 3-54. NEW MEXICO COAL LEASE FEATURES[a]

Item	Statutes	Summary
1. Agency	§ 7-10-1	Comissioner of Public Lands.
2. Requirements		
3. Fees	§ 7-10-1	Fees to be set by commissioner.
4. Rental	§ 7-10-2	See Item #5, Royalty.
5. Royalty	§ 7-10-2	Not less than $0.08 per ton and not less than $3.00 per acre for first year, $4.00 per acre second year or $5.00 per acre year after third year.
6. Duration	§ 7-10-2	Not over five years.
7. Bond		
8. Other Information	§ 7-10-3	Preferential right to lease to previous leasee or previous prospect permit holder.

[a] New Mexico Statutes, 1953

TABLE 3-55. NORTH DAKOTA COAL LEASE FEATURES[a]

Item	Statutes	Summary
1. Agency	§ 38-11 § 38-15-05	The Board of University and School Lands is the only state agency which has leased lands, and it has broad authority to regulate leasing by other state agencies.
2. Requirements		
3. Fees	§ 38-15-05	$10 for lease application for trust lands.
4. Rental	§ 38-15-05	Not less than $1.00 per acre for trust lands.
5. Royalty	§ 38-15-05	Not less than 6%. Current policy is between 10 and 12.5%.
6. Duration		
7. Bond	§ 38-15-03	The industrial commission may require a bond to satisfy conflicts between all mineral developers on the same land - whether coal, oil, gas or otherwise.
8. Other	§ 38-14 § 38-17 § 38-18	See Section 1.6.2.3.2 for additional permit requirements.

[a] Note that it appears only general leasing procedures control state lands of North Dakota for coal leases; coal is specifically exempted from detailed procedures affecting oil and gas leasing and from such detailed procedures affecting uranium and other minerals. Also see § 39-09-02 above.

TABLE 3- 56. SOUTH DAKOTA COAL LEASE[a]

Item	Statutes	Summary
1. Agency	§ 5-7-1	Comissioner of school and public lands.
2. Requirements	§ 5-7-13	A reclamation plan.
3. Fees	§ 5-7-12	$25.00 for application.
4. Rental		
5. Royalty	§ 5-7-12	Fixed by Board of School and Public Lands, but not less than five percent.
6. Duration	§ 5-7-12 § 5-7-15	Not more than five years, with renewal available for five year terms.
7. Bond	§ 5-7-13	Required for payment of royalties. Amount of bond at discretion of commissioner.
8. Other Information	§ 45-7A-3 § 45-7A-2	A report of any exploratory well drilled must be sent to Department of Natural Resources (will be kept confidential). Well must be plugged, capped or sealed.
	§ 5-7-2	This section specifically exempts coal and uranium from a required lease by competitive bidding.
	§ 5-7-11	This section says the permittee may apply for a license (lease). (But says nothing of preference to permittee.)
	§ 45-6A-16	This section exempts state lands from the requirement of a surface mining permit (fee - $50.00) issued by the state conservation commission.

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[a] South Dakota Compiled Laws, 1967

TABLE 3-57. UTAH COAL LEASE[a]

Item	Statutes	Summary
1. Agency	§ 65-1-18	State Land Board.
2. Requirements		
3. Fees	§ 65-1-24	$0.15 per acre
4. Rental	§ 65-1-18	Not less than $0.50 per acre per year nor more than $1.00 per acre per year.
5. Royalty	§ 65-1-18	Not more than 12½ percent of gross.
6. Duration	§ 65-1-18	Not less than 10 years and for so long as producing.
7. Bond	§ 65-1-90	Required only to reinstate lease after failure to pay for damages to surface. Amount of bond discretionary.
8. Other Information	§ 40-8-13 § 40-8-14	If this is a mining operation (surface) the developer must submit a plan of reclamation and before operations start also execute a bond, for surface damage. The Board of Oil, Gas, and Mining controls this aspect. The board determines the amount of bond.
	§ 40-6-5	The Board of Oil, Gas and Mining has the authority to require: a) security (for plugging) b) notice of intent to drill c) filing of a well log (for any drilling).
	§ 65-1-45	Newly acquired lands and lands with an expiring lease must be let through competitive bids, all others leased to first applicant.

[a] Utah Coad Annotated, 1953

TABLE 3-58. WYOMING COAL LEASE[a]

Item	Statutes	Summary
1. Agency	§ 36-74	Board of land commissioners, Commissioner of public lands.
2. Requirements		
3. Fees	§ 36-42	Fee for filing a lease application is $15.00.
4. Rental		
5. Royalty	§ 36-74	Not less than $0.05 per ton.
6. Duration	§ 36-74	Not more than 10 years, with preferential right to renew for 10 year periods.
7. Bond		
8. Other	§ 36-74	The agency above has authority to set rates and terms in its rules and regulations within confines of specific statutes noted above.

[a] Wyoming Statutes of 1957

4) Implied covenants, including the obligation to begin operation, exhibit diligence, protect other coal seams, and comply with abandonment requirements.[1]

3.6.3.2 Health and Safety

The earliest rules and regulations promoting health and safety during mining originated with states.[2] By 1900, most mines in the U.S. were subject to state or territorial regulations of some type. However, these were not always adequately enforced. A series of mine disasters shortly after the turn of the century led to the enactment in 1910 of the first federal legislation calling for an inquiry into the cause of occupational hazards. This led to the establishment of the Bureau of Mines (BuMines) as an investigatory agency--but gave the Bureau no authority to make inspections.

It was not until the Federal Coal Mine Safety Act of 1941[3] that authority providing for inspection of coal mines was enacted, and this was limited to mines engaged in interstate commerce.[4] This Act also required miners to furnish accident information to BuMines inspectors, and authorized the Bureau to make recommendations following its inspections. However, BuMines still was not given enforcement authority.

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[1] Donley, Robert T. "Coal Leases," in Rocky Mountain Mineral Law Foundation, ed., The American Law of Mining, New York, N.Y.: Matthew Bender, Vol. 3, pp. 301-341 (1967).

[2] Pennsylvania, for example, enacted legislation establishing basic health and safety standards for anthracite coal mines in 1869.

[3] Federal Coal Mine Safety Act, Title I. Pub. L.77-49, 55 Stat. 177 (1941).

[4] Freehling, Robert J. "Health and Safety Regulations," in Rocky Mountain Mineral Law Foundation, ed., The American Law of Mining, New York, N.Y.: Matthew Bender, Vol. 3, pp. 714-716 (1967).

In 1952, the Bureau was given its first enforcement authority. The Act passed in that year provided that the Bureau could enforce compliance with underground mining standards in mines employing more than 14 miners.[1] And in 1965, the federal government preempted from the states jurisdiction for health and safety.[2]

By 1966, then, the federal government had assumed overall inspection and enforcement authority in this area. However, in practice, state agencies continued to regulate coal mine health and safety on a day-to-day basis. Finding this unsatisfactory, the federal government enacted the 1969 Federal Coal Mine Health and Safety Act, an all inclusive act preempting for the federal government the entire scope of coal mine health and safety.[3]

The Act established separate specific requirements for surface and underground mines, including specifying maximum dust and noise levels, standards for blasting and explosives, programs for medical examinations and chest x-rays, benefits for disabled miners, and cooperative research programs between the Department of the Interior and the Department of Health, Education and Welfare (HEW).[4]

Passage of the 1970 Occupational Safety and Health Act did not supersede the standards established under the 1969 Act.[5]

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[1] Freehling, Robert J. "Health and Safety Regulations." American Law of Mining. Vol. 3, pp. 714-716.

[2] *Ibid.*

[3] Federal Coal Mine Health & Safety Act of 1969. 30 CFR 70-100.

[4] U.S., Congress, Senate, Committee on Interior and Insular Affairs. Legislative Authority of Federal Agencies with Respect to Fuels and Energy. Staff Analysis. Washington: Government Printing Office. 1973. p. 11.

[5] U.S., Department of Labor, Occupational Safety and Health Administration. "Occupational Safety and Health Standards." Federal Register 37 (October 18, 1972): 22102.

However, the formation of a national policy of occupational health and safety covering all forms of employment necessitated cooperation between BuMines in Interior and the Labor Department's Occupational Safety and Health Administration (OSHA). By 1972, the agencies had eliminated most of the gaps in coverage, duplications of effort, and problems at interagency cooperation, although agreements on jurisdiction were not final.[1] As was the case with the 1969 Act, the Occupational Safety and Health Act limited state participation to areas in which no federal standard was in effect and required approval of state plans by the Secretary.[2]

The Federal Mine Safety and Health Act of 1977[3] combined the standards of the Coal Mine Health and Safety Act of 1969[4] with those set by the Metallic and Nonmetallic Mine Safety Act of 1966,[5] and gave the Secretary of Labor, through his Assistant Secretary for Occupational Safety and Health, overall administration through the Mine Safety and Health Administration (MSHA). Thus, OSHA and MSHA were in the same department, and closer coordination of programs could be accomplished.

Throughout this description, federal agencies have been identified with specific responsibilities. These include USGS,

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[1] U.S., President. Report on Occupational Safety and Health. Washington: Government Printing Office. 1972. pp. 11-12.

[2] Pogson, Stephen W. "Federal Health and Safety Laws Affecting Mining, Milling and Smelting Operations." Rocky Mountain Mineral Law Institute 17 (1972): 242.

[3] Federal Mine Safety and Health Act of 1977, Pub. L. 95-164, 91 Stat. 1290.

[4] Coal Mine Health and Safety Act of 1969, 30 CRF 70-100.

[5] Federal Metallic and Nonmetallic Mine Safety Act of 1966, Pub. L. 89-557, 80 Stat. 772.

BuMines, and MSHA. In brief summary, their responsibilities for mining health and safety are:

1) USGS: Supervising coal mining on federal lands and mineral rights by the federal government on private lands.

2) BuMines: Minimizing occupational hazards for miners through R&D.

3) MSHA: Administering the provisions of the 1977 Federal Mine Safety and Health Act, and coordinating enforcement of the Occupational Safety and Health Act with OSHA.

3.6.3.3. Mining Permits and Reclamation

3.6.3.3a Federal Regulation

Under provisions of the Surface Mining Control and Reclamation Act of 1977,[1] the Office of Surface Mining (OSM) in the Department of Interior is the regulatory agency primarily responsible for receiving mining plans and insuring that rules and regulations established under the Act concerning land reclamation[2] are enforced.

The purposes of the Act include establishing a nationwide program to protect society and the environment from the adverse effects of surface coal mining operations, assuring that the rights of surface landowners are fully protected from such operations, assuring that surface mining operations are not conducted where reclamation as required under the Act is not feasible, assuring that surface coal mining operations are so conducted as to protect the environment, assuring that adequate procedures are undertaken to reclaim surface areas as contemporaneously as possible with the surface coal mining operations, and other purposes to support these and deal with related topics.[1]

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[1] Public Law 95-87, 30 USC 1201 *et seq.*, 91 Stat. 445.

[2] 30 CFR Chapter VII

OSM regulations include air emission and water effluent standards for surface mining which satisfy the Clean Air Act as amended[2] and the Federal Water Pollution Control Act as amended.[3]

3.6.3.3b State Regulation

The Federal Surface Mining Control and Reclamation Act of 1977 (SMCRA) applies to all coal mining operations. Provisions of the Act can be administered by state agencies, with plans approved by OSM. The states of Wyoming and North Dakota both have approved plans. The discussion below refers to reclamation plans established by the states prior to implementation of the SMCRA. These plans in most states are currently being revised.

Some states require that reclamation be integrated into the mining operation. Others require that the lands be reclaimed after the coal has been mined, and since about 1969, some states have begun to specify the uses to which the land should be restored. Prior to 1969, the usual standard was to require that the land be returned to productive use.[4]

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[1] P.L. 95-87, Sec. 102

[2] 42 USC 1857 *et seq.*

[3] 33 USC 1151-1175

[4] U.S., Congress, Senate, Committee on Interior and Insular Affairs. Coal Surface Mining and Reclamation: An Environmental and Economic Assessment of Alternatives. By Council on Environmental Quality, Committee Print. Washington: Government Printing Office. 1973. p. 41.

A major concern here is in reclamation of the surface and that some surfaces do not lend themselves to an acceptable restoration program. Although these are primarily aimed at the control of coal mines, some are also directed at surface mines in general and therefore applicable in this study to those resources having a mining technology which calls for surface disturbance (*i.e.*, coal, uranium, and oil shale).

Table 3-59 summarizes the state reclamation laws by identifying which surface disturbance is to be controlled, what type of controlling mechanism is used, and the agency in charge. The administering agencies listed in the following table are usually given wide discretion in their approval or disapproval of the applicant's reclamation plan and site location. Some statutes list certain factors the agency must consider in making its decision.

Most western states have a permit procedure that requires a reclamation plan be submitted together with evidence of a bond. Bond requirements vary among the states, but generally the bond is determined in relation to the amount necessary to complete the reclamation plan. Some states have statutes specifying the upper and lower limits of the bond. The lowest among the states is $200.00 per acre; $10,000.00 per acre the highest.

Tables 3-60 through 3-62 summarize the open mine permits, as discussed above, in greater detail. As can be seen from the table, the reclamation plan is the key factor in the permit. Although 7 of the 8 states have such permits, only three (Colorado, Montana, and North Dakota) are shown in detail, with the idea being to give a sample of what is generally found in the permits. It is important to note the surface owner in North Dakota, can refuse a strip mine on his surface.

TABLE 3-59. SUMMARY OF STATE MINE RECLAMATION LAWS

	APPLICABILITY				CONTROL MECHANISMS						
	Surface Mines				Type		Requirements				
	General	Coal	Uranium	Underground Mines	Permit Duration	Approval	Bond	Surface Owner Permission	Reclamation Plan	Public Hearing	Controlling Agency
AZ											
CO	X				5 years		X		X		Department of Natural Resources, Land Reclamation Board
MT		X	X	X[1]	1 year		X	X	X		Department of State Lands, State Board of Land Commissioners
ND	X				3 years		X	X	X	X	Public Service Commission
NM		X			See Footnote 2		X		X		Coal Surfacemining Commission
SD	X[3]				1 year		X		X		State Conservation Commission
UT	X			X		X	X		X		Division of Oil, Gas, and Mining, Board of Oil, Gas and Mining
WY	X			X	See Footnote 2		X		X		Environmental Quality Council, Administration of Land Quality

[1] Applies to coal and uranium only.

[2] Permit valid for life of operation.

[3] Does not apply to mines or state lands, only private lands.

TABLE 3-60. COLORADO COAL OPEN MINE PERMIT[a]

Item	Statutes	Summary
1. Agency	§ 34-32-109	Department of Natural Resources (Land Reclamation Board). Division of Mined Land Reclamation.
2. Requirements	§ 34-32-115(4)(a)	Compliance with Colorado Mined Land Reclamation Act of 1976 and Rules and Regulations of Division of Mined Land Reclamation.
3. Fees	§ 34-32-112(6)	$50.00 plus $15.00 per acre for first 50 acres, $10.00 per acre for second 50 acres, $5.00 per acre for third 50 acres, $1.00 per acre for additional acres up to a maximum of $2000.
4. Duration		Valid for life of mine.
5. Bond	§ 34-32-115	Surity of $2000 per acre or sufficient to complete reclamation
6. Discretionary Actions		
7. Other Requirements		Developer has five years to complete reclamation once he starts.
8. Other Information		

[a] Colorado Mined Land Reclamation Act of 1976 and regulations, May, 1977; this same permit is used for any open mine.

TABLE 3-61. MONTANA COAL STRIP AND UNDERGROUND MINING PERMIT[a]

Item	Statutes	Summary
1. Agency	§ 50-1039	Department of State lands, State Board of Land Commissioners.
2. Requirements	§ 50-1039	1. A reclamation plan 2. Proof of right to land 3. Bond (see #5 below)
3. Fees	§ 50-1039	$50.00
4. Duration	§ 50-1039	1 year, renewable each year.
5. Bond	§ 50-1039	$200.00 to $2,500.00 per acre, but minimum of $2,000.00.
6. Discretionary Actions		
7. Other Requirements		
8. Other	§ 50-1041	A prospecting permit is available also (developer must have one or the other) and its fee is $100.00; also requires a reclamation plan and a bond. This permit is good for 1 year, but again renewable.

[a] Revised Codes of Montana, 1947 (applies to all lands in state)

TABLE 3-62. NORTH DAKOTA COAL LEASE (STRIP MINE PERMIT)[a]

Item	Statutes	Summary
1. Agency	§ 38-14-03	Public Service Commission
2. Requirements	§ 38-14-04	1. Reclamation plan with number of acres to be consumed in three years.
3. Fees	§ 38-14-04	$250.00 plus $10.00 per acre for each acre over 50.
4. Duration	§ 38-14-04	Three years for reclamation.
	§ 38-17-05	Ten years renewable.
5. Bond	§ 38-14-07	$1,500.00 per acre or larger if necessary, (developer must pay cost of reclamation regardless of bond limit).
6. Discretionary	§ 38-14-05.1	The commission may decline to issure permit for certain lands (*i.e.*, lands impossible to reclaim).
7. Other Requirements	§ 38-18-06	The surface owner's consent is required; if he refuses, the courts will have to decide rights of parties.
8. Other Information		

[a] North Dakota Century Code, Chapter 38-14 as amended 1975 (applies to all lands in state)

3.7 BENEFICIATION

Beneficiation is the process of upgrading or preparing coal from the mine for subsequent use. The processes included in this category of coal use technology include crushing and screening, physical cleaning, chemical cleaning, drying, and others. After coal has been extracted from the ground, it almost always must be crushed prior to use or sale. This crushing is normally done at the mine site. In addition, many processes requiring a specific size coal may utilize crushing and screening at the process site to ensure that the feed coal is properly sized. The technologies and residuals associated with crushing and screening operations at the mine or process site are included in other sections of this report dealing with the mine or coal processes.

The beneficiation process other than crushing and screening which is most likely to be used in the development of western coal is physical coal cleaning. This process has been utilized in the United States since 1880 and its technology is well established. At present, nearly 50 percent of the annual U.S. coal production is physically cleaned. This amounts to nearly 300 million metric tons annually from over 400 cleaning plants.[1,2]

The decision whether or not to utilize physical coal cleaning is based on many factors. Some of the more important considerations are as follows: purpose of cleaning; air pollution regulations; cost of cleaning; and alternatives to cleaning.

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[1] Lowry, H. H. ed. Chemistry of Coal Utilization, 2 vols. and supplementary volume. New York: Wiley, 1945, 1963 (supplementary volume).

[2] Nielsen, George F., ed. 1974 Keystone Coal Industry Manual. New York: McGraw-Hill, Mining Publications, 1974.

The purpose of cleaning the coal is important in that the end use of the coal may dictate whether cleaning will be beneficial. For example, if the coal is to be used as a feed for a high-Btu coal gasification facility, cleaning will be of limited value. This is because sulfur removal processes are included in the design of the gasification plant and would be needed even if clean coal were used. Coal cleaning, therefore, would introduce an unnecessary step in the coal use scheme. If, however, the coal is to be used as fuel for boilers in the production of electricity, physical cleaning might be desirable. This is because SO_2 emissions from the power plant can be controlled either by reducing the sulfur in the coal or by using flue gas desulfurization techniques. It must be decided, therefore, whether desulfurization by physical coal cleaning or flue gas cleaning should be practiced.

An important factor in this decision is air pollution regulations. That is, will the sulfur removal accomplished by physical cleaning adequately protect air quality and meet all legal standards? This determination is primarily dependent on the characteristics of the coal to be cleaned and the regulation involved.

The type of coal is important in that, as will be discussed in Section 3.7.1, physical cleaning can only remove pyritic sulfur from coal. In a low sulfur western coal where total sulfur content may be approximately one percent, the percent pyritic sulfur in the coal can be as low as 0.05 percent.[1] The removal of even 100 percent of the pyritic sulfur from this coal would not significantly affect SO_2 emissions upon combustion. If, however, the coal contained 0.6 percent pyritic sulfur, SO_2

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[1] Neilsen, George F., ed. 1977 Keystone Coal Industry Manual. New York: McGraw-Hill Mining Publications, 1977.

emissions could possibly be reduced by about 50 percent (assuming 80 percent removal of pyritic sulfur in the cleaning process). This degree of cleaning, however, would most likely result in a significantly reduced coal yield.[1]

Another important coal characteristic which must be considered in this regard is the size distribution of the pyritic sulfur particles in the coal. Smaller particles of pyritic sulfur in the coal result in reduced cleaning efficiency.[2]

After the potential level of cleaning has been determined from the coal characteristics, the affect on compliance with regulations must be determined. For example, under the current Federal New Source Performance Standards, a new power plant boiler must not cause SO_2 emissions greater than 1.2 $lb/10^6$ Btu heat input.[3] Physical coal cleaning may not be able to meet this requirement. In addition, under the 1977 Amendments to the Clean Air Act[4] a specific percentage reduction in emissions will be required at new facilities. Considering that physical coal cleaning has limited capabilities for reducing the total sulfur percent, these future regulations will become an important consideration.[5]

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[1] Deurbrouck, A. W. Sulfur Reduction Potential of the Coals of the United States. Report of Investigations 7633. Pittsburgh, Pa.: Pittsburgh Energy Research Center, 1972. Washington, Bureau of Mines, Dept. of Interior.

[2] McCartney, J. T., H. J. O'Donnell, and Sabri Ergun. Pyrite Size Distribution and Coal-Pyritic Particle Association in Steam Coals. Correlation with Pyrite Removal by Float-Sink Methods. R.I. 7231. Washington: Bureau of Mines, 1969.

[3] 40 CFR Part 60

[4] 42 U.S.C., 1857 *et seq.*

[5] It is not the intent of this section to list all applicable regulations or suggest any compliance scheme or philosophy. Instead, the section is to merely point out that regulations must be considered.

The third general consideration, cost of cleaning, is important for two reasons. First, as is discussed further in Section 3.7.1, the higher the percent sulfur removal, the lower the overall yield. That is, operating the cleaning facility to effect a higher sulfur removal will cause high coal losses. If, for example, the desired sulfur level can only be achieved with a 50 percent coal loss, the cost might be prohibitive. The second cost analysis involves a determination of the savings by the end user relative to the cost of cleaning. If flue gas desulfurization is less expensive than cleaning or would be required even if cleaning was used, the cost of cleaning might exceed the benefit.

The fourth consideration, alternatives, must be considered in light of the factors discussed above. Since there are several methods to accomplish the desired end result of reduced SO_2 emissions, each alternative must be considered in light of the specific circumstances and conditions at the proposed facility. These available alternatives include flue gas desulfurization, alternative fuels, alternative combustion techniques, synthetic fuel production, chemical cleaning and others.

As can be seen from the above discussion, the decision whether or not to utilize physical coal cleaning is dependent on many considerations. These considerations change from one site to another and even with time as economics and regulations change. It is, therefore, impossible to make a generalized decision as to the use of physical coal cleaning with western coal. Instead, the following sections present a description of a typical physical coal cleaning plant and a quantification of residuals associated with the process.

3.7.1 Technologies

Physical coal cleaning removes impurities, such as pyrite (FeS_2), ash, and rock, from coal by a mechanical separation process based on a gravity difference between coal (which is relatively light) and contaminants (which are heavier).[1] One of the primary advantages of coal cleaning is that is removes much of the sulfur from coal, thereby reducing or eliminating the need for a flue gas desulfurization system at a coal-fired facility.

Sulfur occurs in raw coal in three forms: pyritic, organic and sulfate. The quantity of sulfates is almost always negligible. The organic sulfur compounds are chemically bound in the coal, but the pyritic sulfur, although sometimes widely dispersed throughout the coal, is separate from the coal itself. Physical coal cleaning is limited to the removal of the pyritic sulfur which accounts for between 5 and 60 percent of the sulfur in the coal.

The exact processes and equipment which can be used for physical coal cleaning vary widely. Although it is not possible to describe a universally applicable coal cleaning process, within most plants there are generalized processing areas which can be identified. These include initial coal preparation, fine coal processing, coarse coal processing and water management, and final coal preparation. Figure 3-20 shows a generalized flow diagram for this type of plant.

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[1] Paul Weir Company, Inc. An Economic Feasibility Study of Coal Desulfurization, Volume I. Chicago, Ill.: October, 1965.

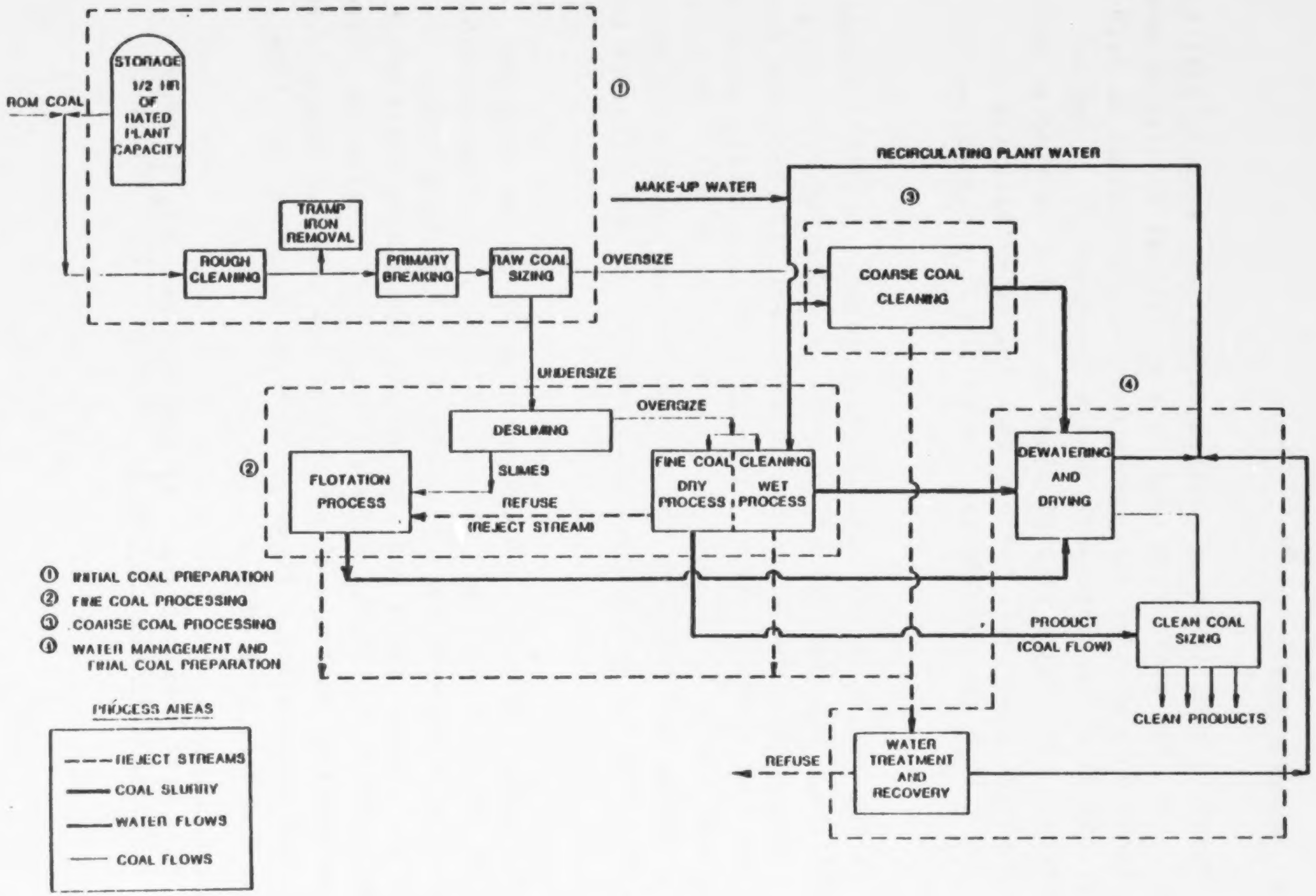
ROM COAL
STORAGE
1/2 HR OF RATED PLANT CAPACITY
①
ROUGH CLEANING
TRAMP IRON REMOVAL
PRIMARY BREAKING
RAW COAL SIZING
OVERSIZE
MAKE-UP WATER
RECIRCULATING PLANT WATER
③
COARSE COAL CLEANING
UNDERSIZE
OVERSIZE
DESLIMING
②
FLOTATION PROCESS
SLIMES
REFUSE
(REJECT STREAM)
FINE COAL CLEANING
DRY PROCESS
WET PROCESS
④
DEWATERING AND DRYING
PRODUCT
(COAL FLOW)
CLEAN COAL SIZING
CLEAN PRODUCTS
REFUSE
WATER TREATMENT AND RECOVERY
① INITIAL COAL PREPARATION
② FINE COAL PROCESSING
③ COARSE COAL PROCESSING
④ WATER MANAGEMENT AND FINAL COAL PREPARATION
PROCESS AREAS
REJECT STREAMS
COAL SLURRY
WATER FLOWS
COAL FLOWS

Figure 3-20. Generalized Coal Cleaning Process.

3.7.1a Initial Preparation

The first operation in coal cleaning, initial preparation, involves crushing and screening of the raw coal. The coal is first subjected to primary crushing to release large particles of impurities such as clay, rock and pyrite. This crushed coal is then screened and the larger portions are sometimes recrushed. After all crushing, the coal is screened to produce a coarse coal fraction and a fine coal fraction which are fed to separate cleaning processes.

The final coal processing area of a cleaning plant can employ both wet and dry cleaning operations. In plants using a dry coal cleaning process, fine coal from the initial preparation step flows to a feed hopper and then to an air cleaning operation. This cleaning operation can employ one of several devices which rely on an upward current of air traveling through a fluidized bed of crushed coal to effect separation by particle size and density. The lighter coal particles are carried out the top of the fluidized bed in the air stream and the heavier sulfur and ash particles are taken out the bottom. Product coal streams from a dry cleaning process are sent directly to the final coal preparation step while reject ash and pyrite streams are usually processed further in wet cleaning operations.[1]

3.7.1b Fine Coal Processing

Traditionally, fine coal processing operations employ wet cleaning equipment since the design and operation of wet cleaning devices is a more established technology.[2] However, the limited availability of water in the west has discouraged the use of wet cleaning processes. At present, there are many wet cleaning designs used for fine coal cleaning. These include: jigs, heavy-medium cyclones, water tables, spiral classifiers, hydrocyclones, froth floatation, and numerous variations on these basic designs. The underlying principal in all these designs is gravity separation. The specific gravity of coal is approximately 1.27 while the specific gravity of most impurities ranges from 2.0 to 5.0. The cleaning process effects a separation by first creating a slurry with water and the crushed coal. The coal and impurities are then separated, utilizing the differences in specific gravity between the coal and the impurities. This separation can either be effectuated by pulsating the water through the solids causing the heavier materials to settle to the bottom (jigs and water tables) or by utilizing centrifugal force as in a cyclone to separate out the heavier materials (heavy-medium cyclones, hydrocyclones, and spiral classifiers).

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[1] "Fine-Coal Treatment and Water Handling," Coal Age 66 (12), 67 (1961).

[2] Leonard, Joseph W. and David R. Mitchell, eds. Coal Preparation, 3rd edition. New York: The American Institute of Mining, Metallurgica., and Petroleum Engineers, Inc., 1968.

A third mechanism used in separation is froth floatation. In this process ultrafine coal particles are separated from the remaining solids by causing them to rise to the top of the water/coal slurry in a froth. This is accomplished by treating the coal with a frothing agent (usually an alcohol) which renders the coal air adsorbent and water repellant but does not affect the impurities. This slurry is then subjected to vigorous agitation and aeration causing the coal to attract air bubbles and float to the top where it is withdrawn.

3.7.1c Coarse Coal Processing

In coal cleaning practice, coarse coal is processed independently of the fines. In many cases, the equipment used to process coarse material is identical to that used for fines, although operating parameters vary. Advantages of separating the fine from the coarse cleaning operations include improved removal of pyrite and ash impurities, higher plant yield, and higher cleaning equipment throughput.

Feed to the coarse coal processing area of the plant consists of oversize material (76 x 6.5 mm particles) from the initial preparation area. This feed stream is slurried with water prior to cleaning since coarse coal cleaning operations generally employ wet processing equipment to remove impurities from the coal. The coarse coal slurry is fed to one of the many types of process equipment currently employed in coarse coal cleaning. Here, impurities are separated from the coal by differences in their densities. It is also common practice to remove a middling fraction from the separation operation and process it further by means of recycle or by feed to another cleaning process. Two streams are removed from the coarse coal processing area: a product coal stream and reject stream.

In actual practice, there are usually several types of coarse coal cleaning devices used in a single plant. These include jigs, tables, heavy media separation equipment, launders, and hydrocyclones. Typically, sizing of coarse coal may be used to isolate feed streams for individual cleaning operations, or the reject from one type of cleaning device may serve as the feed to another. Jigs are the most common cleaning devices employed by the industry. In many instances they represent the only type of cleaning device operation in a cleaning plant. The jigs used for coarse cleaning are nearly identical to those used for fines cleaning. As was described previously, jigs effect coal cleaning by the use of pulsating water in a bed of raw coal. The lighter coal particles move to the top of the bed while the heavier impurities move to the bottom.

Another cleaning mechanism which is coming into widespread use is heavy media separation. Heavy media separation employs a suspension of magnetite and water to produce a liquid with a specific gravity in the range 1.3 to 1.6. There are numerous types of heavy-medium devices, all of which operate by floating the clean coal (specific gravity of 1.27) in the heavy media and sinking the impurities (specific gravity of 1.3 to 5.0). This method of coal cleaning is the best suited to optimizing sulfur reduction in coal cleaning practice.[1,2,3]

The third type of coarse coal cleaning equipment used is the table. Water tables are commonly employed to process coarse material in a coal cleaning plant, although air tables are sometimes used. The principals of table operation are identical to that discussed previously for fines cleaning. Operating experience with tables handling unclassified material has proven that tables are highly efficient in making separations at specific gravities higher than 1.50. However, at lower specific gravities, which are desirable for attaining maximum sulfur reduction, table efficiency decreases. Therefore, if maximum sulfur reduction in desired, it is necessary to reprocess the product and reject streams from table operations in some other type of cleaning equipment.[4]

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[1] Battelle-Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. EPA Contract No. 68-01-0470. Columbus, Ohio: 1973.

[2] Terchick, A. A. "Sulphur Reduction Through Improved Coal Washing Practices," Mining Congress Journal 57(7), 48-55 (1971).

[3] Hudy, J., Jr. Performance Characteristics of Coal-Washing Equipment, Dense-Medium Coarse-Coal Vessels. R.I. 7154. Bureau of Mines, 1968.

[4] Terchick, A. A., *op. cit.*

Another type of process used to clean coarse coal is a launderer. They are simple to install and operate, although they do not effect as clean a separation between coal and its impurities as do most other devices. Launderers employ a flowing current of water in a channel to separate coal and refuse. A fluidized bed is formed in the channel with the coal stratifying according to density: the lighter particles at the top of the bed and the heavier particles on the bottom. Refuse is removed from a port in the bottom of the channel while the product flows to the dewatering and drying area of the plant.

The hydrocyclone is often used to clean very coarse coal. As was discussed earlier, a hydrocyclone cleans the coal through the use of centrifugal force. Although hydrocyclones are employed in both coarse and fine processing, the former is a more limited application. Hydrocyclone processing of coarse coal does not produce an acceptable clean coal product. A significant quantity of impurities still contaminates the product stream from a hydrocyclone and a large fraction of the uncontaminated coal is removed with the ash and pyrite reject.

3.7.1d Coal Dewatering and Drying

After the raw coal has been crushed and cleaned by the wet cleaning methods described above, the clean coal product must be dewatered and dried. Dewatering and drying equipment are used on the product flows from both the fine and coarse coal preparation areas. Typically, cleaning plants employ mechanical dewatering operations to separate coal slurries into a low-moisture solid and a clarified liquid. The solid coal sludge produced in the dewatering step can then be mechanically or thermally dried to further reduce the wet cleaning operations in the plant. Commonly, fine clean coal is not processed in the same dewatering/drying equipment as the coarse product.

Dewatering equipment may consist of one or more of the following: dewatering screens, thickeners, and cyclones. In dewatering service, screens are used primarily for fine processing, while thickeners and centrifuges process both coarse and fine coal.[1] It should be noted that coal cleaned by the dry processes, such as air tables, does not require dewatering.

The drying operation is usually the final processing step in treating the cleaned coal product. Drying operations may employ equipment such as filters, centrifuges and thermal dryers. The former are mechanical devices which do not completely dry the coal (3 to 6 percent remaining moisture) while the latter uses combustion air to remove 97 to 100 percent of the moisture. Drying is practiced for one or more of the following reasons: (1) to avoid freezing difficulties and to facilitate handling during shipment, storage, and transfer to the points of use; (2) to maintain high pulverizer efficiency; (3) to increase the heating value of the coal; and (4) to decrease transportation costs.

Centrifuges are mechanical devices which use strong centrifugal force to dry fine coal products from primary dewatering units. Coal slurry is fed to the centrifuge where it is subjected to the high acceleration and centrifugal force of a rapidly spinning conical basket. Water flows out of minute perforations in the basket while the coal slides from the apex to the base and is removed as a dewatered cake.[2,3]

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[1] Reid, George W. and Leale E. Streebin. Evaluation of Waste Waters from Petroleum and Coal Processing. PB 214 610. EP1.23/2:72.001. University of Oklahoma, School of Civil Engineering & Environmental Science, 1972.

[2] *Ibid.*

[3] Leonard, Joseph W. and David R. Mitchell, eds. Coal Preparation, 3rd edition. New York: The American Institute of Mining, Metallurgica., and Petroleum Engineers, Inc., 1968.

Filters take a suspension with a high percentage of solids and separate the water to produce a compact wet cake of coal solids. This process is performed by placing a filter with a cloth or screen surface in the suspension. The filter has a suction behind the surface so that water and solids are drawn into the filter. The solids are trapped on the surface: the water is drawn through the filter and separated from the solids. The solids trapped on the filtering surface are removed from the suspension as a cake and air is drawn through them into the filter to remove as much of the surface moisture as possible. To complete the continuous cycle the air pressure in the filter is increased to greater than atmospheric. The solids are blown from the surface of the filter and removed.[1]

The thermal dryers used in coal cleaning plants are continuous direct contact dryers which employ convection as the major principal of heat transfer. In direct contact dryers, hot combustion gases and wet coal are brought into intimate contact with each other on a continuous gas flow/coal feed basis. The hot gases are generated in a combustion chamber and fed to the drying chamber via a fan or blower. Typically, there are particulate emissions associated with thermal dryers because fine coal is entrained in the hot drying gases. They usually necessitate addition of a particulate control device.[2] Also, some sulfur oxides, nitrogen oxides, and hydrocarbons will be present in the combustion gases.

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[1] Reid, George W. and Leale E. Streebin. Evaluation of Waste Waters from Petroleum and Coal Processing. PB 214 610. EP1.23/2:72.001. University of Oklahoma, School of Civil Engineering & Environmental Science, 1972.

[2] *Ibid.*

3.7.1e Water Management

The final processing area in the coal cleaning plant is the water management area which separates plant water from the refuse. This area is needed due to the large amounts of recirculating water used in the wet cleaning processes. Equipment employed to dewater the refuse includes dewatering screens and thickeners. Efficient water management is essential for minimizing the quantity of makeup water that must be added to the circulating plant water. Close quality control on the quantity of suspended solids is also needed to promote efficient operation of the cleaning plant.

The solids product from the refuse dewatering is dried, commonly by filtration, and discarded in refuse piles. The water from these operations is pumped to settling ponds to remove finely suspended solids. This operation often requires the addition of flocculating agents to accelerate and enhance settling.

As can be seen from the above discussion, the primary difference between physical coal cleaning plants is the equipment used for the cleaning. The purpose and principles of operation of most of the alternatives are very similar. Table 3-63 shows the operating parameters of these various alternatives. The major differences in residuals produced by these facilities will be caused by the choice of whether to use the dry process or the wet process and whether or not to use thermal dryers.

For the subsequent analysis, it is assumed that wet cleaning and centrifugal dryers are used. Thermal dryers are not used since the major considerations involved (transportation

TABLE 3-63. COAL CLEANING EQUIPMENT OPERATING PARAMETERS

Type of Cleaner	Separating Gravity	Feed Size Range	Capacity (Metric tons per hour)	Relative Cleaning Costs
Airflow Cleaner*	1.5 to 1.6	6.3 mm to 14 mesh	15 to 320	Medium
Air Tables*	1.5 to 1.6	6.3 mm to 40 mesh	10 to 14	Medium
Centrifugal/Electrostatic Separator	Not available	60 to 400	Not available	Not available
Jigs*	1.5 to 1.6	150 mm to 40 mesh	5 to 640	Low
Heavy-Medium Cyclones*	1.3 to 1.6	38 mm to 35 mesh	45 to 70	High
Water Tables*	1.5 to 1.6	38 mm to 48 mesh	10 to 14	Low/medium
Hydrocyclones*	1.4 to 1.6	6.3 mm to 0	4 to 62	Low
Spiral Classifiers*	1.5 to 1.6	10 to 200 mesh	.5 to 2.0	Low/medium
Froth Flotation*	Not available	28 to 325 mesh	2.5 to 15	High
Heavy-Medium Separators	1.3 to 1.6	150 mm to 35 mesh	10 to 820	Medium
Launders	1.5 to 1.6	150 mm to 60 mesh	26 to 115	Low

*Requires close-sized feed. Actual range depends on coal and operating conditions.

costs and process operations) do not mandate their use. That is, the coal use facilities considered subsequently are mine mouth operations and there would be little if any improved overall efficienty associated with thermal drying.

However, the coal conversion facilities discussed in Sectio Section 3.8 may require dried coal but the drying is included in the process designs. In addition, in some of the northern states thermal drying may help prevent freezing of the coal while in storage or transport during colder periods.

3.7.2 Input Requirements

The beneficiation plant which was chosen for quantification of input requirements for physical coal cleaning was based on the capacity required to clean the coal from a 12 MMTPY mine. The coal which is mined is assumed to have a heating value of 8600 Btu/lb. This is a typical value for western subbituminous coal. For example, the coal mined at both Farmington, New Mexico, and Colstrip, Montana, has this heating value. It is also assumed that the beneficiation plant uses the wet process to physically clean the coal and has an overall yield of 75% and a heat recovery of 90%. That is, 25% of the input coal is lost as impurities and 10% of the heating value is lost as residual coal in the impurities. The actual yield in facilities currently operating ranges from 65 to 90%.[1]

The coal rates and heating values on this basis are shown in Table 3-64. It should also be noted that this coal cleaning rate would provide approximately enough coal to operate a 3000 MW generation facility operating at a 34% efficiency and a load factor of 0.7.

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[1] Hoffman, L., et al. The Physical Desulfurization of Coal. Major Considerations of SO_2 Emission Control. McLean, Virginia: Mitre Corp., 1970. Pb 210 273.

TABLE 3-64. COAL RATES - PHYSICAL COAL CLEANING

	Plant Rate	Heating Value	Heat Rate
Input Coal (R.O.M.)	12,000,000 TPY	8,600 Btu/lb	23.7×10^9 Btu/hr
Cleaned Coal (Output)	9,000,000 TPY	10,300 Btu/lb	21.4×10^9 Btu/hr

3.7.2a Manpower Requirements

Manpower estimates for this coal cleaning facility were developed on the basis of a detailed analysis of a coal utilization complex which included a physical coal cleaning plant capable of producing 10 million TPY of clean coal from 13 million TPY of R.O.M. coal.[1] To estimate the manpower required for construction of a beneficiation plant, it is assumed that the ratio between capital costs of a beneficiation plant and capital costs of a surface mine will be the same as the ratio of beneficiation plant construction personnel to mine plant construction personnel. The capital costs ratio is approximately 1:3.[2] Therefore, scaling down Table 3-27 (Section 3.6.1.2a) by a factor of 3, the following construction schedule is assumed:

	Year 1	Year 2	Year 3	Year 4	Year 5
Total Workers	12	50	70	70	56

Manpower requirements for operating the coal cleaning facility have been estimated by Ralph M. Parsons to be 22 people. These requirements are itemized in Table 3-65.

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[1] Ralph M. Parsons Co. Commercial Complex Conceptual Design/Economic Analysis, Oil and Power by COED Based Coal Conversion. Pasadena, Calif.: Ralph M. Parsons Co., 1975.

[2] It is assumed in this analysis that the design of the 25,000 TPD physical coal cleaning plant is the same as the design of the 27,450 TPD plant as reported in: Ralph M. Parsons Co., *op. cit.*

TABLE 3-65. COAL PREPARATION OPERATING AND MAINTENANCE LABOR

Category	Number of Employees Per Shift	Total
Operating Labor		
• Operator	1	4
• Helper	2	8
TOTAL	3	12
Maintenance Labor	---	10

Source: Ralph M. Parsons Co. Commercial Complex Conceptual Design/Economic Analysis, Oil and Power by COED Based Coal Conversion. Pasadena, Calif.: Ralph M. Parsons Co., 1975.

3.7.2b Materials and Equipment

Table 3-66 lists the major pieces of equipment required for a 9 million TPY beneficiation plant.[1] These estimates are based on a detailed conceptual design of a commercial coal conversion complex.

3.7.2c Economics

Table 3-67 lists the estimated capital costs for the 9 million TPY coal cleaning plant.[2] These capital costs include the capital costs, start-up costs, financing and working capital. Depreciable capital costs total 35 million dollars and an additional 2 million dollars is required for working capital. Operating costs have also be estimated by Ralph M. Parsons to be 2.8 million dollars per year (Table 3-68). These estimates are in 1974 dollars.

3.7.2d Water Requirements

The coal cleaning plant considered here operates with total recirculation of the process water. That is, the water used to wash the coal is reused instead of discharging it from the process. The major source of water leaving the wet cleaning process considered here is a blowdown which must be removed and replaced with clean water to keep the recirculating water below 15 to 20 percent total solids.[3] This blowdown is sent to settling

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[1] It is assumed in this analysis that the design of the 9 million TPY physical coal cleaning plant is the same as the design of the 27,450 TPD plant as reported in: Ralph M. Parsons Co., *op. cit.*

[2] *Ibid.*

[3] Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle-Columbus Laboratories, 1973.

TABLE 3-66. MAJOR EQUIPMENT SUMMARY - 9 MILLION TPY COAL BENEFICIATION PLANT

Number Items	Description	Size
	Pumps	
3	Waste Dewatering Screen Undersize Pumps	300 gpm ea 15 ft TDH
4	Clean Coal Fines Pumps	4,000 gpm ea 100 ft TDH
3	Cyclone Feed Pumps	2,200 gpm ea 55 ft TDH
2	Tailings Pumps	200 gpm ea 50 ft TDH
2	Recycle Water Pumps	5,000 gpm ea 150 ft TDH
2	Gland Water Pumps	50 gpm ea 150 ft TDH
	Other Major Equipment	
1	Recycle Water Tank	200,000 gal
1	Head Tank	100,000 gal
2	Reciprocating Plate Feeders	750 TPH
1	54" ROM Coal Conveyor	1,500 TPH
1	54" Coal Conveyor	1,300 TPH
1	54" Rev Conveyor	1,300 TPH
12	Vibrating Feeders	200 TPH ea
2	36" Jig Feed Conveyors	600 TPH ea
2	Middling Recycle Conveyors	14 TPH ea
1	Clean Coal Conveyor No. 1	800 TPH
1	Clean Coal Conveyor No. 2	800 TPH
12	Vibrating Feeders	135 TPH ea
1	Clean Coal Collecting Conveyor	800 TPH
1	Clean Coal Tripper Conveyor	800 TPH
6	Belt Feeders	135 TPH ea

(continued)

TABLE 3-66. (Continued)

Number Items	Description	Size
	Other Major Equipment (Continued)	
1	Drying and Classification Feed Belt Conveyor	2,500 TPH
2	Waste Conveyors	45 TPH ea
1	Waste Conveyor	90 TPH
1	Waste Conveyor	150 TPH
1	Centrifuge Cake Conveyor	310 TPH
3	Belt Feeders	105 TPH ea
1	Transfer Belt Conveyor to Stockpile	1,300 TPH
1	Transfer Belt Conveyor from Stockpile	1,300 TPH
2	2-Stage, 4 Roll Crushers	7 TPH ea
6	Coal Crushers	800 TPH ea
1	10' x 20' Rotary Coal Breaker	1,500 TPH
4	Centrifuges	500 gpm ea
2	Baum Type Coal Jigs	180 f^2, 600 TPH ea
1	75' Dia Thickener	5,000 gpm
1	ROM Hopper	300 tons
2	Unwashed Coal Silos	10,000 tons ea
2	Clean Coal Silos	10,000 tons ea
1	Clean Coal Crusher Feed Bin	1,500 tons
1	8' x 16' Scalping Screen	1,300 TPH
4	8' x 16' DD Clean Coal Screens	300 TPH ea
2	4' x 6' DD Middling Screens	11 TPH ea
2	Waste Dewatering Screens	45 TPH ea
16	14" Dia Cyclones	15,000 gpm total
4	6' Stationary Cross-Flow Screens	100 TPH ea
4	7' x 16' Single Deck Screens	80 TPH ea
24	12' Dia Cyclones	4,300 gpm total
4	3' Stationary Cross-Flow Screens	3 TPH ea
1	Belt Scale	2,000 TPH

(Continued)

TABLE 3-66. (Continued)

Number Items	Description	Size
	Other Major Equipment (Continued)	
1	Tramp Iron Magnet	54" wide
2	Tramp Metal Detectors	
2	Belt Scales	750 TPH ea
2	Automatic Belt Samplers	
1	Weight Scale	1,000 TPH
1	Rail Mounted Stacker/Reclaimer	2,250 TPH Stacking
2	Diesel Engine Bulldozer	Heavy Duty

Source: Ralph M. Parsons Co. Commercial Complex Conceptual Design/Economic Analysis, Oil and Power by COED Based Coal Conversion. Pasadena, Calif.: Ralph M. Parsons Co., 1975.

TABLE 3-67. CAPITAL COSTS - 9 MILLION TPY COAL BENEFICIATION PLANT

Item	Cost[a] ($ million)
Fixed Capital Investment[b]	29.00
Start-up Costs	2.00
Construction Financing[c]	3.75
Depreciable Investment	34.75
Working Capital	1.75
Plant Operation Life	20 yr
Useful Life for Depreciation	11 yr
Depreciation Method	DDB[d]

[a] First Quarter 1974 dollars.

[b] Includes home office engineering and sales tax.

[c] Applicable to cases using 65% debt at 9% interest and 0.75% committment fee only.

[d] Double declining balance.

Source: Ralph M. Parsons Co. Commercial Complex Conceptual Design/Economic Analysis, Oil and Power by COED Based Coal Conversion. Pasadena, Calif.: Ralph M. Parsons Co., 1975.

TABLE 3-68. ANNUAL OPERATING COSTS - 9 MILLION TPY COAL BENEFICIATION PLANT

Item	Cost[a] ($ Million)
Materials and Supplies	
Operating Supplies	0.145
Maintenance Materials and Contract Labor	1.110
Total Materials and Supplies	1.225
Labor	
Operating Labor and Supervision	0.137
Maintenance Labor and Supervision	0.250
Plant Overhead	0.099
Payroll Burden	0.172
Total Labor Costs	0.658
G and A Overhead	
Taxes and Insurance	0.870
Total Operating Costs	2.825

[a] First Quarter 1974 dollars.

Source: Ralph M. Parsons Co. Commercial Complex Conceptual Design/Economic Analysis, Oil and Power by COED Based Coal Conversion. Pasadena, Calif.: Ralph M. Parsons Co., 1975.

ponds where it is treated to facilitate solids settling. The clear supernatant from these settling ponds is used as a makeup water to replace part of the blowdown.

The only water actually lost to the process is that which leaves the plant with the clean coal or evaporates from the process. This water must be replaced with a makeup water. This water consumption is approximately 3.3% of total plant water or 50 to 70 gallons per ton of coal processed. The makeup water required to clean the 9 million TPY of R.O.M. coal, therefore, is approximately 1400 gpm.

3.7.2e Land Requirements

The land requirements for a physical coal cleaning facility of the size considered here have been estimated to be between 40 and 90 acres.[1] The larger acreages are required if extensive lagooning or ponding is undertaken. Since the plant considered here is assumed to utilize complete water recycle with extensive use of settling ponds, the maximum acreage of 90 acres was assumed.

3.7.2f Ancillary Energy

Coal cleaning operations employ various mechanical devices in the processing steps. These include crushers, pumps, compressors, dryers, and other equipment, all of which have ancillary energy requirements. These have been estimated to be 5.1×10^4 Btu/ton of coal cleaned[2] or approximately 1.7×10^9 Btu/day for a facility which produces 9 million TPY of cleaned coal.

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[1] Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle Columbus Laboratories, 1973.

[2] Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supplied by Emerging Technologies, Draft Report. HIT-573. Columbia, Md.: 1974.

The primary source of this energy is electricity which is either generated at the plant or purchased. It is assumed for this analysis that the plant does not include facilities for electric generation.

3.7.3 Outputs

The physical coal cleaning facility used to quantify outputs is the same facility described previously for quantification of inputs in Section 3.7.2. As was discussed previously, this facility uses the wet process to produce 9 million TPY of clean coal from 12 million TPY of R.O.M. coal. In addition, the facility considered does not utilize thermal drying of the coal.

3.7.3a Air Emissions

The three potential sources of air emissions at any physical coal cleaning facility are: particulate coal dust from process operations; particulate emissions and combustion products from thermal drying; and combustion products from burning coal refuse piles.

Process emissions are generated by coal preparation steps such as crushing or breaking and by cleaning steps such as air tabling as used in the dry cleaning process. The crushing operations at the facility considered here are enclosed and use modern control technoloiges to minimize emissions of particulates. Based on EPA emission factors, emissions from controlled coal crushing are as low as 0.005 lbs/tons of coal. For a 12 million TPY coal crushing operation, the particulate emission rate is approximately 7 lbs/hr.[1] In addition, since the process considered here does not use the dry cleaning process, there are no process emissions.

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[1] U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. EPA Publication AP-42, Research Triangle Park, N.C.: U.S. Government Printing Office. 1977. p. 3.2.7.

The second category of emissions from physical coal cleaning facilities, thermal drying, is not a factor at the facility considered here since all drying is done by methods other than thermal dryers. (See Section 3.7.1) It may, however, be necessary to use this type of drying if freezing of the coal becomes a problem at some of the colder sites. For this reason, Table 3-69 was included to indicate the level of air emissions which would be generated by the use of a thermal dryer at a 9 million TPY coal cleaning plant.

TABLE 3-69. AIR EMISSIONS FROM THERMAL DRYERS AT A 9 MILLION TPY COAL CLEANING PLANT

Contaminant	Uncontrolled Emissions Potential (lb/hr)	Controlled Emissions (lb/hr)
SO_x	260	4.3[1]
NO_x	130	130
Particulates	21,000	210[2]

[1] 85% SO_x Control

[2] 99.9% Particulate Control

Source: Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Contract No. 68-01-0470. Columbus, Ohio: 1973.

Coal preparation plants also produce refuse piles consisting mainly of sulfur-rich coal. Improper disposal of the refuse pile may initiate low-temperature oxidation of the coal with an accompanying increase in temperature within the pile. Ultimately, this can result in the ignition of the refuse pile, from which significant quantities of combustion gases can be emitted. This can be prevented by recovering the area with soil and revegetating the area during reclamation.[1] The air emissions from the 9 million TPY coal cleaning facility, therefore, are assumed to consist of only 7 lb/hr of particulates.

3.7.3b Water Effluents

Water effluent contaminants from the coal beneficiation process consist of suspended solids, which are chiefly fine clay and coal, and dissolved solids, which may contain iron, aluminum, calcium, magnesium, sodium, and potassium. Water effluents may also contain surface-active organic compounds such as alcohols or kerosene, which are added in some coal cleaning plants to enhance frothability in the process. Water contaminants in refuse pile runoff are sulfuric acid, sulfates, manganese, and iron. However, in a modern plant, all liquid waste streams are routed to holding ponds to allow settling of the suspended solids. The clear supernatant liquid is then recycled to the process. In addition, contamination of ground and surface waters by percolation of effluent from the settling pond should be minimal with a properly designed and maintained lined settling pond.[2] Water effluents from this coal cleaning plant, therefore, are essentially negligible.

3.7.3c Solid Wastes

Solid wastes from the physical coal cleaning facility are generated by removal of impurities from the R.O.M. coal. These impurities plus any retained coal become solid waste after being removed from the process streams by screening and/or settling. The quantity of these solid wastes depends primarily on the characteristics of the input coal and the specifications which the output clean coal must meet. As was discussed previously, the plant yield as determined by the above factors can range from 60 to 90 percent. The solid waste production, therefore, ranges from 10 to 40 percent of the input coal. The quantity of solid waste generated by the 9 million TPY facility operating at 75% yield considered here is 8000 TPD. Since the mine is available for back-filling at the mine-mouth operation considered here and proper piling and reclamation are assumed to be practiced, and there should be no problem with solid waste disposal.

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[1] Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Contract No. 68-01-0470. Columbus, Ohio: 1973.

[2] *Ibid.* See also Gavande, S. A., "Survey of Technological and Environmental Aspects of Wet Residual Disposal in Evaporative Holding Ponds," Radian Corporation, 1978.

3.7.3.d Noise Pollution

Physical coal cleaning facilities use machinery for the physical handling and processing of coal. One substantial byproduct of solids handling is noise. Worker exposure to noise varies, but typical in-plant noise levels exceed 90 dbA when uncontrolled.[1] However, since the Coal Mine Health and Safety Act of 1969 requires that no unprotected worker may be exposed to noise levels greater than 90 dbA continuously for an 8-hour shift, it is assumed that noise levels within the plant will be controlled along with provision for worker protection.

To provide adequate in-plant worker hearing protection, the plant design and operation will have to include provisions for noise control on machinery and provisions for protective devices for employees. The actual mix of machinery and protection cannot be specified since it would vary with design choices. If more noise control equipment is used, abnormal operations can be more easily detected and the danger of permanent hearing damage is lessened. The sources of the in-plant noise and typical control methods are shown in Table 3-70.

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[1] Patterson, W. N., E. E. Ungar and G. F. Fox, "Noise Control in Coal Cleaning Plants", in Noise Control Proceedings: Bureau of Mines Technology Transfer Seminar, Pittsburgh, Pa., January 22, 1975. U.S. Bureau of Mines, 1975, pp. 86-96.

The noise levels which will be present at and beyond the cleaning facility property boundary are not presently defined. However, assuming maximum use of in-plant noise control methods this form of pollution is not expected to constitute a problem.

3.7.3e Occupational Health and Safety

Data on injuries, deaths and man-days lost for a beneficiation plant are applied directly from Battelle's data to the 9 million TPY facility as described earlier. This analysis indicates that 0.56 deaths and 11 injuries will occur annually, and 4900 man-days will be lost each year.[1]

SUMMARY

Table 3-71 presents a summary of the direct impacts associated with a 9 million TPY coal beneficiation plant.

3.7.4 Social Controls

Western coals are typically crushed, sized, and stored prior to being used at the mine site or being shipped to processing/conversion facilities. Depending on coal type and/or method of transport, the coal may also be cleaned and dried. Appropriate

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[1] Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Contract No. 68-01-0470. Columbus, Ohio: 1973.

TABLE 3-70. SOURCES OF NOISE AT A PHYSICAL COAL CLEANING PLANT

Equipment	Typical Noise Level, dbA	Noise Control Method
Baum jigs	100	Mufflers (10)
Do	95	Damp sides
Rotary dump	85	None
Scalping screens (reciprocating)	98	Rubber lining
Picking table (reciprocating)	98	Damping and partial enclosure
Crushers	100	Enclosures
Refuse screens (shaker drive)	100	Rubber lining enclose drive
Clean coal screens (shaker drive)	95	Rubber lining enclose drives
Centrifugal dryers	95	Enclosures
Disk filters	85	None
Vacuum pumps	95	Mufflers, lagging
Roots blowers	95	Mufflers, enclosures
Conveyors (flighted)	90	Damp trough, blades
Conveyors (belt)	80	None
Conveyor drive	95	Enclosures
Chutes	90	Ledges, lining, damp
Diester tables	85	None
Vibrating feeder	90	Partial enclosures
Fans	95	Muffler

Source: Patterson, W. N., E. E. Ungar and G. Fox. "Noise Control in Coal Cleaning Plants", in Noise Control Proceedings: Bureau of Mines Technology Transfer Seminar, Pittsburgh, Pa., January 22, 1975. U.S. Bureau of Mines, 1975, pp. 86-96.

TABLE 3-71. SUMMARY OF IMPACTS ASSOCIATED WITH A 9 MILLION TPY COAL BENEFICIATION PLANT

Inputs	
Manpower	
construction	258 man-year
operating	22 men
Materials and Equipment	Table 3-66
Economics[a]	
capital cost	\$36.5 million
operating cost	\$ 2.8 million/yr
Water	1400 gpm
Land	90 acres
Ancillary Energy	1.7 x 10^9 Btu/day
Outputs	
Air Emissions	7 lb/hr
Water Effluents	None
Solid Wastes	8,000 ton/day
Noise Pollution	Negligible
Occupational Health and Safety	
deaths	0.56 deaths/yr
injuries	11 injuries/yr
man-days lost	4,900 man-days/yr

[a] 1974 dollars

land use, impact statement, right-of-way and other requirements must be met and procedures followed. A number of these regulations are described earlier in sections on generally applicable social controls and coal mining, and processing/conversion. The section on processing/conversion social controls should also be referred to the identification of applicable water and air quality, solid waste disposal, and safety regulations. There are no specific new source performance standards limiting emissions from emissions or effluent discharge standards for beneficiation facilities, and the general air and water quality social controls are discussed in the section on processing. In the following section, regulatory activies significant for beneficiation are described. In the following section, regulatory activities significant for beneficiation are described.

There are no specific new source performance standards limiting emissions from beneficiation facilities, but facilities must comply with prevention of significant deterioration (PSD) standards for air quality, and must obtain a National Pollutant Discharge Elimination System (NPDES) permit for water effluents.[1]

Beneficiation facilities are generally under the jurisdiction of the Mine Safety and Health Administration (MSHA) under provisions of the Federal Mine Safety and Health Act of 1977.[2]

3.7.4a Solid Waste

Solid wastes from beneficiation activities are described generally in the section on mine reclamation and in the section on the disposal of processing wastes. In some areas refuse piles from beneficiation activities may accumulate, and have potential for becoming a major safety or environmental hazard. Requirements exist for weekly inspection of piles that act as dams. These piles must be of "substantial construction" and must be designed according to accepted dam engineering criteria.[3] In addition, the stability of all refuse piles must be maintained, and appropriate provisions must be made to guard against explosion or combustion.[1]

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[1] These standards, which are generally applicable, are discussed in Chapter 2 on General Social Controls.

[2] Federal Mine Safety and Health Act of 1977, Pub. L. 95-164, 91 Stat. 1290.

[3] 30 CFR 77.216.

3.7.4b Air, Water and Noise

Beneficiation facilities at both surface and underground coal mines have controls over worker exposure to pollutants similar to those in other mine areas. In addition, however, a number of specific rules apply to surface working areas and federal regulations have been developed that apply to specific pieces of beneficiation equipment.[2] Each facility must conduct sampling, inspection, and compliance to standards as is required in other areas of federal mine safety law. The following sections briefly identify selected regulations for crushing and drying facilities as required by MSHA.

Dust Standards and Airborne Contaminants

Dust standards for beneficiation work areas have received significant consideration, including the specification of who, where, when, and how dust samples will be collected, and how these will be analyzed.[3] Violation of acceptable dust levels (20 milligrams per cubic meter), necessitates methods of further dust control, and also initiates a more intensive sampling program until the deficiency has been corrected.

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[1] New regulations concerning solid waste disposal are being promulgated as a result of the Surface Mine Control and Reclamation Act of 1977, Pub. L. 95-87, 30 USC 1201. These regulations were not final as of the date of publication of this document.

[2] 30 CFR 77.

[3] 30 CFR 71.1.

Drinking Water and Sanitation Facilities

MSHA has established standards of adequacy and location on the bathing facilities, and toilets (including flush toilets) and on the quality, distribution and dispensing of drinking water.[1] Both installation requirements and maintenance of these facilities are covered in the regulations.

Noise Standards

MSHA requires that beneficiation facilities have periodic measurements of noise levels, and requires that each working shift maintain noise levels at or below the current standard.

3.7.4c Equipment Standards

MSHA equipment standards apparently cover both safety and process equipment used in beneficiation facilities.[2] For example, dryers, crushers, screeners and other beneficiation equipment are covered by safety provisions such as proper electrical connection canopies, guards and safety switches. Thermal driers have received extensive mandatory safety standards.[3] Requirements for these devices include various safety doors and vents, provisions for adequate access and maintenance, installation and fire protection provisions, alarm devices, fail-safe monitoring systems, wet-coal feed bin level indicators and other automatic monitoring equipment.

Personnel Certification and Safety Standards

A number of personnel working in beneficiation facilities must be certified by MSHA before performing various functions. These include testing and maintenance personnel involved in electrical work, methane monitoring, hoistmen, and training activities.

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[1] 30 CFR 71.

[2] 30 CFR 77.

[3] 30 CFR 77.300.

3.8 CONVERSION

Coal can be used in several ways. The most familiar is direct combustion in a furnace for the production of steam. Two other methods involve extraction of the small percentage of hydrocarbons that exist in coal plus chemical alteration of a large portion of the carbon in the coal to produce hydrocarbons. These two methods are gasification and liquefaction. This section will present a process description of several coal conversion processes, and quantify many of the input requirements and outputs associated with each process.

Gasification and liquefaction of coal are currently being investigated in the U.S. as two methods to supplement dwindling domestic natural gas and crude oil reserves. The technologies associated with both types of conversion processes have not yet been demonstrated on a commercial scale in the U.S. The technologies described in this section are those which are most advanced and may proceed to commercial operation. Direct combustion of coal to provide steam for electrical generation is also considered since it will probably continue to be the major end use of coal.

3.8.1 Gasification

Coal may be transformed into a gaseous product by heating the coal to drive off highly volatile constituents and by partially oxidizing the carbon in the coal to carbon monoxide. The carbon monoxide formed may then be upgraded to methane by catalytically reacting carbon monoxide and hydrogen. This is a simplified explanation to give the reader an overall concept of the goal of all gasification schemes. The following discussion will provide more insight into the various gasification schemes.

3.8.1.1 Technology Description

3.8.1.1a Basic Gasification Process

The three primary chemical inputs needed for synthesizing gas from coal are carbon, hydrogen, and oxygen. Coal provides the carbon; steam is the most commonly used source of hydrogen (although hydrogen is sometimes introduced directly from an external source); and oxygen is usually supplied as either air or pure oxygen. Heat can be supplied either directly by combusting coal and oxygen inside the gasifier or indirectly by hot pebbles or ceramic balls from an external source.

Three combustible gases produced by coal gasification processes are carbon monoxide (CO), methane (CH_4) and hydrogen (H_2). Methane, the primary component of natural gas, is similar to natural gas in heating value. The heating values of carbon monoxide and hydrogen are approximately one-third the methane/natural gas value. Several noncombustible gases are also produced, including carbon dioxide, hydrogen sulfide and nitrogen.

A major goal for most coal gasification processes is to maximize the heating value of the product gas during the initial gasification stage. The properties of the product gas from each gasification process are determined primarily by the methods used to introduce oxygen, hydrogen, and heat into the gasifier. Each method involves trade-offs. For example, the first requirement, oxygen supply, can be met by introducing either air or pure oxygen. If air is used to provide the oxygen, however, nitrogen is introduced as an undesirable by-product into the gas stream and dilutes the heating value of the gas to between 100 and 250 Btu/scf. Although pure oxygen is more expensive than air, it eliminates the nitrogen problem and produces a gas with a heating value between 250 and 450 Btu/scf.

The second requirement, hydrogen, can be met by introducing steam or hydrogen. The use of steam to introduce hydrogen into the process produces primarily carbon monoxide and hydrogen, while the direct introduction of hydrogen produces methane and carbon. Since reacting hydrogen directly with coal also produces heat, hydrogen would seem preferable to steam, but the amount of methane produced is usually quite small. The other method of introducing hydrogen, the steam-carbon reaction (heat + $C + H_2O \rightarrow CO + H_2$), is used more frequently.

The third requirement, heat, can be supplied either directly or indirectly. For coal gasification processes, direct heat is more thermally efficient than indirect heat. However, most direct heat processes use either air or oxygen as an oxidizer, producing the products identified above. One alternative direct heating method feeds hot lime (CaO) into the gasifier where its exothermic reaction with carbon dioxide produces heat. The primary gaseous products are carbon monoxide and hydrogen. Indirect heating using molten salts, dolomite solids, molten metal, pebbles, etc., have also been proposed, but this introduces additional materials requirements and makes the gasification more complicated.

The types and proportions of gases produced are determined by the design of the specific gasification process. As indicated above, the basic chemical choices are whether to use hydrogen or steam, air or oxygen, and direct or indirect heat. On the basis of the options selected and specific conditions such as temperature and pressure, reactor vessels can be divided into three general categories: gasifier, hydrogasifier, and devolatilizer. Gasification systems employ one or more of these reactor types.

The gasifier reactor produces some gas through the steam-carbon reaction (heat + $C + H_2O \rightarrow CO + H_2$) and some through the water-gas shift reaction ($CO + H_2O \rightarrow CO_2 + H_2$ + heat). The major differences in gasifier reactor systems are in the method of providing heat and oxygen.

In the second type of reactor, hydrogasifier, methane is produced by reacting hydrogen with coal or char under pressure ($C + 2H_2 \rightarrow CH_4$ + heat). Although systems of this type differ in the method of supplying hydrogen, all hydrogasifiers produce up to twice as much methane as gasifiers or devolatilizers of comparable capacity.

In the third possible system, a devolatilizer, the coal is thermally decomposed. In this system, the raw coal is heated, and tars, oils, naphthas and other relatively light hydrocarbons are driven off.

Although these three systems present three distinct methods of generating hydrocarbons from coal, most reactor designs incorporate all three methods to some extent. For example, although hydrogen is not introduced directly into a gasifier reactor, the hydrogen produced by the steam-carbon reactions promotes some hydrogasification. In addition, the heat generated by the partial oxidation in the gasifier promotes devolatilization.

Gasification systems can also be categorized on the basis of engineering features, two significant ones being whether the system is pressurized and the type of coal bed used. Gasification systems may be operated either at high pressure (up to about 1500 psi) or at atmospheric pressure. The main advantages gained from pressurizing are improved quality of product gas, maximization of the hydrogasification reaction, reduction of equipment size, and elimination of the need to separately pressurize gas before introducing it into a pipeline.[1]

There are three basic bed types for gasification systems: fixed-bed, fluidized-bed, and entrainment.[2] In the fixed-bed system, a grate supports lumps of coal through which the steam or hydrogen is passed. These gasifiers sometimes include a mechanism for physically moving the coal through the reactors, for example, a moving grate. These systems are sometimes referred to as moving-bed reactors. Conventional fixed-bed systems are incompatible with caking coals (coals which, when heated, pass through a plastic stage and cake or agglomerate into a mass). To expand the range of coals that can be used, the moving-bed systems are modified to incorporate a rotating grate or stirrer to prevent caking.

The fluidized-bed system uses finely sized coal. Gas is passed through the coal, producing a lifting and "boiling" effect. The result is an agitated bed with more exposed coal surface area to promote the chemical reactions. Fluidized-bed systems also have a limited capacity for operating with caking coals; consequently, these coals are often pretreated to destroy caking characteristics when the fluidized-bed system is used.

Finely sized coal is also used in entrainment systems. In this type of system, the coal particles are transported in the gas (for example, steam and oxygen) prior to introduction into the reactor. The chemical reactions occur in the reactor, and the product gases and ash are taken out separately. There are no limitations on the types of coal that can be used with the entrainment system. A summary of the advantages and disadvantages of each of these bed types is shown in Table 3-72.

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[1] Interagency Synthetic Fuels Task Force. Report to Project Independence Blueprint, Federal Energy Agency, Supplement I, prepared under the direction of U.S. Department of the Interior, 1974.

[2] Corey, Richard C. "Coal Technology", pp. 23-61 in Riegels' Handbook of Industrial Chemistry, 7th Ed. New York: Van Nostrand Reinhold, 1974.

As can be seen from the above discussion, there are many possible options available in the coal gasification reactor. In addition to the reactor, however, there are other processing steps. The choice of reactor design and subsequent processing will categorize the process into one of three general categories of gasification schemes: Low-Btu gasification, which produces a low heat content gas (100-250 Btu/scf); Medium-Btu gasification, which yields an intermediate quality gas (250-450 Btu/scf); and High-Btu gasification, which produces a high-Btu gas or pipeline quality gas (900-1000 Btu/scf).

The basic differences between these three types of gasification systems are the source of oxygen for partial oxidation in the gasifier and whether or not a methanation step is used to convert the carbon monoxide to methane. A summary of the alternative generally used within each category is as follows:

1) Low-Btu gasification: air used as a source of oxygen; no methanation

2) Medium-Btu gasification: pure oxygen used; no methanation

3) High-Btu gasification: pure oxygen used, methanation step included.

TABLE 3-72. ADVANTAGES AND DISADVANTAGES OF COAL GASIFICATION PROCESS TYPES

Process Type	Advantages	Disadvantages
Fixed Bed	• High carbon conversion efficiency • Low ash carryover • Low temperature operation • Highest turndown capability	• Sized coal required • Coal fines must be briquetted • Produces tars and heavier hydrocarbons which must be washed from the gas • Produces phenols which can cause pollution problems • Low capacity-largest number of gasifiers required • Low temperature gas produced seriously restricting waste heat steam generation pressures • Present experience based on discharging dry ash • Caking coal technology not commercially proven
Fluid Bed	• Turndown capability • High degree of process uniformity • Excellent solids gas contact • Lower residence time than fixed bed gasifier (higher coal throughput per unit volume of reactor)	• Requires dry coal for feeding • Requires sized coal • Requires complicated gas distributor • Caking coals require pretreatment • Fluidization requirement sensitive to fuel characteristics • Single-stage • High carbon loss with ash • Low pressure
Entrained Bed	• Handles all type coal, no pretreatment required • Excellent solids-gas contract • No tar formation • No phenol formation • High capacity per unit volume of reactor • Produces inert slagged ash	• Single-stage • Low pressure • Poor turndown capability • Air-blown and two-stage gasification still under development

A summary of the characteristics of several gasification processes for the production of each type of gas is shown in Table 3-73. It should be noted, however, that new technology in this area is under consideration by many agencies and firms. There are, therefore, other processes in various stages of development and other processes which will probably be developed in the future. The processes considered here are those gasification processes which are advanced enough to allow an adequate technological description and analysis. In addition to these gasification processes, there are several hydrogasification processes which are in various stages of development. These processes are not considered in detail.

The reactions involved for the production of all three categories of product gas will be discussed and the process schemes defined. However, only the High-Btu gasification process will be examined thoroughly since it is the one that is most likely to be employed in western coal development. The reasons is that transporation costs (pipeline pumping costs) are inversely proportional to the quality of the gas. For example, three cubic feet of 300 Btu/scf gas must be delivered to meet the same energy demand as can be supplied by one cubic foot of 900 Btu/scf gas. Therefore, low and medium Btu gas will be produced only if there is a local demand. For completeness, low and medium gasification are briefly discussed, followed by a thorough analysis of high Btu gasification.

3.8.1b Low and Medium Btu Gasification

Low Btu gas (150-250 Btu/scf) can be used as fuel in either a conventional boiler or a combined cycle generation plant. Medium Btu gas (250-450 Btu/scf) can be used either as a chemical feedstock or as fuel in a conventional boiler or combined cycle generating plant. Medium Btu gas can be produced in a low Btu

TABLE 3-73. CHARACTERISTICS OF SELECTED COAL GASIFICATION PROCESSES

Processes	Developer	Heating Value of the Product Gas		Type of Reactor			Operating Pressure		
		Low	High/Medium	Fluid-Bed	Entrained-Bed	Moving-Bed	Low[1]	Medium[2]	High[3]
ATGAS	Applied Technology Corp.	X	X	Molten-Iron Bath			X		
CO_2 Acceptor	Conoco Coal Development Co.		X	X				X	
Koppers-Totzek	Heinrich Koppers GmbH of Essen		X		X		X		
Lurgi	Lurgi Mineralötechnik GmbH	X	X			X		X	
Molten Salt	M. W. Kellogg Company		X	Molten-Salt Bath					X
Synthane	U.S. Bureau of Mines	X	X	X					X
Texaco	Texaco Development Corp.	X	X		X				X
U-GAS ®	Institute of Gas Technology	X		X				X	
Union Carbide	Union Carbide Corp.		X	X				X	
Wellman-Galusha	Wellman Engineering Co.	X	X			X	X		
Westinghouse	Westinghouse Research Laboratories	X		X				X	
Winkler	Davy Powergas Inc.	X	X	X			X		

[1] Typically 0 - 15 psig

[2] 100 - 500 psig

[3] 1000 - 1500 psig

Adapted from: Bodle, W. W. K. C. Vyas and A. T. Talwalkar. "Clean Fuels From Coal - Technical-Historical Background and Principles of Modern Technology" in Clean Fuels From Coal Symposium II Papers. Sponsored by Institute of Gas Technology, June 23-27, 1975, pp. 11-51.

gasification plant by substituting 98+% oxygen for air as the source of oxygen to the gasifier. Because the processing steps necessary to produce medium Btu gas are identical to those required for low Btu gasification, the following sections, which describe the low Btu process features, will apply to medium Btu gasification as well.

The processing steps in a low or medium Btu gasification plant are (1) coal pretreatment and gasification, (2) cooling and solids removal, (3) acid gas removal, (4) sulfur recovery, and (5) product drying and compressing. Figure 3-21 shows the general flow for these processes. The gasification step is the major distinguishing feature among various designs. In each gasifier, coal is reacted with oxygen to produce a raw gas rich in CO and H_2 which can be purified and used as a boiler fuel. The differences between the processes are found in the operating temperatures, pressures and mechanical characteristics of the gasifier.

The reactions taking place in the gasifier are given by Equations 3-1 to 3-3.

$$\text{coal} \rightarrow CH_4 + \text{char} + \text{heat} \tag{3-1}$$

$$C + H_2O + \text{heat} \rightarrow CO + H_2 \tag{3-2}$$

$$2C + O_2 \rightarrow 2CO + \text{heat} \tag{3-3}$$

The design for each gasifier listed in Table 3-73 which is capable of producing low- and/or medium-Btu gas except Lurgi and Synthane is briefly discussed below. The designs of the Lurgi and Synthane processes are discussed in detail subsequently in Section 3.8.1.1c.

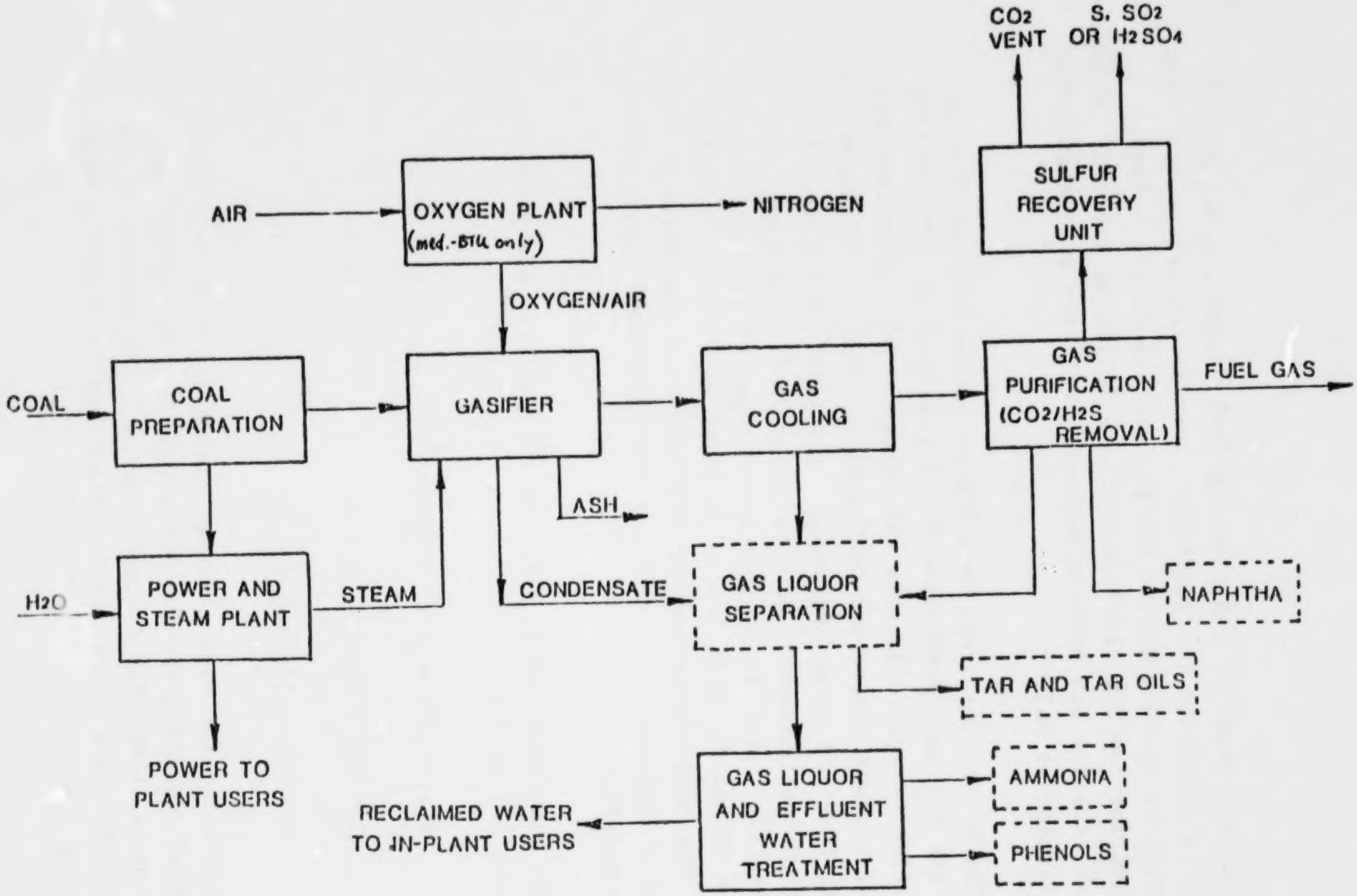
CO2 VENT
S. SO2 OR H2SO4
SULFUR RECOVERY UNIT
AIR
OXYGEN PLANT (med.-BTU only)
NITROGEN
OXYGEN/AIR
COAL
COAL PREPARATION
GASIFIER
GAS COOLING
GAS PURIFICATION (CO2/H2S REMOVAL)
FUEL GAS
ASH
H2O
POWER AND STEAM PLANT
STEAM
CONDENSATE
GAS LIQUOR SEPARATION
NAPHTHA
TAR AND TAR OILS
POWER TO PLANT USERS
GAS LIQUOR AND EFFLUENT WATER TREATMENT
AMMONIA
PHENOLS
RECLAIMED WATER TO IN-PLANT USERS

Figure 3-21. General Coal Gasification Flow Sheet

ATGAS Gasifier

This type of gasification process can be broken down into two basic types: Two-Stage process (low-Btu) and PATGAS (medium-Btu). In each type, crushed (-$^{1}/_{4}$ in), dried (4% moisture) coal is injected into a molten iron bath. The low-Btu process uses compressed air for coal injection while the medium-Btu process uses a steam lance. The coal dissolves in the molten iron where the coal volatiles crack and are converted into carbon monoxide and hydrogen. The fixed carbon in the coal reacts with oxygen and steam, producing more carbon monoxide and hydrogen. Sulfur from coal migrates to a lime slag floating on the molten iron and forms calcium sulfide. The slag containing ash and sulfur is continuously withdrawn from the gasifier and desulfurized with steam to yield elemental sulfur and desulfurized slag. A portion of the desulfurized slag is recycled to the reactor. The conditions of operation of the gasifier are about 2600°F and 5 psig. The same type of gasifier can be used in conjunction with a shift conversion, methanation and compression to produce a high-Btu gas.

The composition and heat content of low- and medium-Btu gases are as follows:[1]

Low-Btu gas:	30% CO, 15% H_2, 55% N_2; 190 Btu/scf
Medium-Btu gas:	64.5% CO, 35% H_2, o.5% N_2; 315 Btu/scf.

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[1] Bodle, W. W., and K. C. Vyas. "Clean Fuels From Coal-Introduction To Modern Processes" in Clean Fuels From Coal Symposium II Papers. Sponsored by Institute of Gas Technology, June 23-27, 1975, pp. 11-51.

CO_2 Acceptor

The CO_2 acceptor utilizes two fluidized bed reactors. One reactor is used for gasification of the coal and the other is used to regenerate spent acceptor (limestone or dolomite) used in the process. This system is different from most gasification processes in that the heat required for the gasification reactions is generated inside the gasifier but not by partial oxidation of the coal. Instead, heat is provided by introducing the acceptor into the reactor where it exothermically reacts with CO_2. The CO_2 for this reaction is provided by the water-CO shift reaction (Equation 3-4 below).

After the acceptor reacts according to the Equation 3-5, it is removed from the gasifier and introduced to the second reactor where it is calcined according to Equation 3-6. The calcined acceptor is then recirculated to the gasifier.

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad (3\text{-}4)$$

$$CaO + CO_2 \rightarrow CaCO_3 + \text{Heat} \qquad (3\text{-}5)$$

$$CaCO_3 \rightarrow CaO + CO_2 \qquad (3\text{-}6)$$

The coal feed for the gasifier is first crushed (+100 -8 mesh), dried and preheated. It is then fed to the gasifier from lock hoppers by gravity feed near the bottom of the gasifier. Steam is injected at about this same level. Hot recirculating acceptor from the regenerator reactor is showered through the fluidized bed and collects at the bottom. Thus, the fluidized bed is a mixture of coal, char and acceptor. Steam is injected near the bottom of the gasifier to strip the char from the acceptor and the spent acceptor is then removed to the regenerator

The heating value of the medium-Btu gas produced by this process is expected to be about 440 Btu/scf (dry basis).

Koppers-Totzek Gasifier

The Koppers-Totzek gasifier is an entrained flow gasifier capable of treating all types of coal. Coal pulverized to 70% through a 200-mesh screen is fed to the gasifier with steam and air or oxygen through coaxial burners at each end of the gasifier. Coal, oxygen and steam react at about 3300°F to produce the raw gas. Part of the coal ash is slagged and removed from the bottom of the gasifier. The remaining ash and raw gas leave the top of the gasifier and are processed by the downstream equipment described subsequently. The gasifier pressure is approximately atmospheric. The typical composition of the medium-Btu raw gas (in mole %) and its heating value are as follows: 50.4% CO, 5.6% CO_2, 33.1% H_2, 9.6% H_2O, 0.3% H_2S + COS and 1.0% N_2; heating value = 298 Btu/scf.[1]

Molten Salt Gasifier

In this process, dried, crushed (12 mesh) coal is picked up from lock hoppers by a preheated steam and oxygen stream and fed into the gasifier along with sodium carbonate. The coal steam reaction (see Equation 3-2) is catalyzed by the molten salt (sodium carbonate) contained in the reactor so that a gas free of tars is produced at a sufficiently low temperature and appreciable methane production can also take place. The use of the molten salt reaction medium also makes pretreatment of caking coals unnecessary. A bleed stream of molten salt containing the coal ash in solution is withdrawn from the bottom of the gasifier, and is contacted with water to dissolve sodium carbonate. Ash is separated by filtration. Sodium carbonate solution is carbonated to precipitate bicarbonate. The bicarbonate is filtered out and calcined to restore the carbonate salt which is then recycled to the gasifier.

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[1] Bodle, W. W., and K. C. Vyas. "Clean Fuels From Coal-Introduction to Modern Processes" in Clean Fuels From Coal Symposium II Papers. Sponsored by Institute of Gas Technology. June 23-27, 1975, pp. 11-51.

The composition (in mole%) and heating value of the typical raw medium-Btu gas from the process is as follows: 26% CO, 10.3% CO_2, 5.8% CH_4, 34.8% H_2, 0.2% H_2S, 0.3% N_2 and 22.6% heating value = 329 Btu/scf.[1]

Texaco Gasifier[2,3,4,5]

The coal for this process is first pulverized to 70% through 200 mesh. It is then mixed with water and this coal-water slurry is heated to about 1000°F. The resulting steam-coal mixture is then fed into the top of the gasifier. Heated oxygen is fed to the gasifier at the periphery of the vessel to produce a medium Btu gas. Temperatures in the reaction zone range from 2000 to 2500°F and the operating pressure is about 400 psi. The gasifier can also be blown with air to produce a low-Btu gas. Ash is removed from the bottom of the gasifier as a molten slag and is water quenched.

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[1] Bodle, W. W., and K. C. Vyas. "Clean Fuels From Coal-Introduction To Modern Processes" in Clean Fuels From Coal Symposium II Papers. Sponsored by Institute of Gas Technology, June 23-27, 1975, pp. 11-51.

[2] Howard-Smith, I., and G. J. Werner. Coal Conversion Technology. Chemical Technology Review#66, Park Ridge, N.J., Noyes Data, 1976.

[3] Hendrickson, Thomas, comp. Synthetic Fuels Data Handbook. Denver, Colorado, Cameron Engineers, Inc., 1975.

[4] Katz, Donald L., et al. Evaluation of Coal Conversion Processes to Provide Clean Fuels, Final Report. EPRI 206-0-0. Ann Arbor, Mich., Univ. of Michigan, College of Engineering, 1974.

[5] Hall, E. H., et al. Fuels Technology: A State-of-the-Art Review. EPA 650/2-75-034, EPA Contract No. 68-02-1323, Task 14. Columbus, Ohio, Battelle Columbus Labs., April 1975.

The composition (in volume %, dry) and heat content of the resulting gas has been estimated as follows: 38.7% H_2, 46.6% CO, 11.5% CO_2, 0.7% CH_4, 2.0% N_2 and 0.7% H_2S; heat content = 270 Btu/scf.

U-GAS Gasifier

In this gasifier design, crushed coal is fed through lock hoppers to a pretreater (necessary for caking coals only) which operates at 350 psi and 800°F. Air introduced into the pretreater partially oxidizes the coal to destroy its caking tendencies. From the pretreater the coal is fed directly to the fluid-bed gasifier that operates at 350 psi and 1900°F. Air and steam are introduced to the bottom of the gasifier. Dry ash is removed from the gasifier through lock hoppers.

The composition (in mole %) of the raw gas from the gasifier is as follows: 17.0% CO, 8.8% CO_2, 11.6% H_2, 12.0% H_2O, 4.1% CH_4, 45.4% N_2 and 0.6% H_2S. The approximate heating value of this gas is 150 Btu/scf (dry basis).[1]

Union Carbide Gasifier

This gasification process involves a two-stage fluidized-bed system. In the first stage, coal is fed to a fluidized bed burner where it is combusted with air to form hot pelletized coal ash. This ash is fed to the gasifier along with crushed (minus 35 mesh) coal and steam. The ash from the burner provides the heat for the gasifier. Thus, air rather than oxygen can be used for combustion without dilution of the gasifier off gas with nitrogen. The hot ash enters the gasifier at about 2000°F and is cooled to about 1000°F within the gasifier. The raw gas leaves the gasifier at about 1600 to 1800°F. The heating value of this gas is expected to be about 300+ Btu/scf.[1]

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[1] Bodle, W. W., and K. C. Vyas. "Clean Fuels From Coal-Introduction To Modern Processes" in Clean Fuels From Coal Symposium II Papers. Sponsored by Institute of Gas Technology, June 23-27, 1975, pp. 11-51.

Wellman-Galusha Gasifier

The Wellman-Galusha gasifier is a moving bed, steam-air gasifier. Coal crushed and sized to $^3/_{16}$ to $^5/_{16}$-inch diameter is fed to the gasifier through a lock hopper and distributed over the coal bed by a rotating arm. The coal bed moves downward through the gasification zone, undergoing reaction 3-1. As the resulting char leaves the gasification zone and enters the combustion zone, it contacts steam and oxygen injected at the bottom of the gasifier and undergoes reactions 3-2 and 3-3. Air is injected for low-Btu gas. A revolving eccentric grate at the bottom of the gasifier allows for bed support and ash removal. A rotating agitator arm, located just below the coal bed, is used when handling slightly caking coals.

Strongly caking coals must be pretreated to destroy their caking tendencies before gasification can be accomplished. The gas flows counter-currently to the coal bed and is removed from the top of the gasifier at 1000-1200°F. The gasifier operates at essentially atmospheric pressure.[2]

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[1] Hendrickson, Thomas, comp. Synthetic Fuels Data Handbook. Denver, Colorado, Cameron Engineers, Inc., 1975.

[2] Ball, D., et al. Study of Potential Problems and Optimum Opportunities in Retrofitting Industrial Processes to Low and Intermediate Energy Gas from Coal, Final Report. Columbus, Ohio, Battelle Columbus Labs, 1974.

The heating value of the medium-Btu gas produced in this process is approximately 270 Btu/scf.[1] The heating value of the low-Btu gas is 120 to 168 Btu/scf.[1,2]

Westinghouse Gasifier

In this gasification process, dry coal is first fed to the bottom of a devolitizer/desulfurizer reactor while dolomite is fed into the top. The reactor is a fluidized bed reactor operating at 1600 to 1800°F. It produces a low-Btu off-gas rich in CO, H_2 and N_2 with smaller amounts of CH_4. The sulfur is removed by a reaction of the H_2S and the dolomite to form calcium sulfide. The char produced in this reactor is then gasified with steam and air in a combustor/gasifier operating at about 2100°F. The off-gas from this vessel is reintroduced into the bottom of the devolitizer/desulfurizer. Both vessels operate at between 150 and 250 psi.[3]

Winkler Gasifier

The Winkler gasifier is a fluid bed, steam-air (low-Btu) or steam-oxygen (medium-Btu) gasifier. Coal crushed to a 3/8-inch maximum diameter is dried and fed by screw conveyors to the gasifier. The coal undergoes reactions 3-1 to 3-3 to yield a raw gas rich in CO and H_2. The gasifier reaction temperature is

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[1] Howard-Smith, I., and G. J. Werner, Coal Conversion Technology. Chemical Technology Review #66, Park Ridge, N.J., Noyes Data, 1976.

[2] Ball, D. A., et al. Environmental Aspects of Retrofitting Two Industries to Low- and Intermediate-Energy Gas from Coal. EPA-600/2-76-102, EPA Contract No. 68-02-1843. Columbus, Ohio, Battelle-Columbus Laboratories, April 1976.

[3] Chemical Engineering Progress. Coal Processing Technology, Vol. 2. N.Y., AIChE, 1975.

1500-1850°F and the pressure is about atmospheric. Thirty percent of the coal ash is removed from the bottom of the gasifier while about 70 percent is carried overhead with the raw gas. Above the fluid bed, additional steam and air or oxygen are injected to react with the remaining carbon. The resultant gas is processed by the equipment described under common processing steps.

The composition (in mole %) and heating value of the resulting medium-Btu gas are as follows: 25.7% CO, 15.8% CO_2, 32.2% H_2, 23.1% H_2O, 2.4% CH_4 and 0.8% N_2; heating value = 275 Btu/scf (dry basis).[1]

The composition (in mole %) and heating value of the resulting low-Btu gas are as follows: 19% CO, 6.2% CO_2, 11.7% H_2, 11.5% H_2O, 0.5% CH_4 and 51.1% N_2; heating value = 118 Btu/scf (dry basis).[1]

The above discussions are intended to give the reader an introduction into the technologies of low- and medium-Btu gasification processes. In each process except U-GAS and Westinghouse, a high-Btu gas can be produced by using the gasification techniques to produce a medium-Btu raw gas and then further processing this gas to increase heating value by the methods described in Section 3.8.1.1c for the Lurgi and Synthane high-Btu processes.

Once the raw low- or medium-Btu gas is produced by one of the gasification systems described above, it must undergo two additional processing steps to make it usable as a fuel. Common technology is used in all processes downstream of the gasifier and is briefly discussed in the following paragraphs.

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[1] Bodle, W. W., and K. C. Vyas. "Clean Fuels From Coal-Introduction To Modern Processes" in Clean Fuels From Coal Symposium II Papers. Sponsored by Institute of Gas Technology, June 23-27, 1975, pp. 11-51.

First, entrained solids and/or liquids must be removed by cooling and/or washing. This may be accomplished by many methods, of which cyclones, venturi scrubbers or direct quenches are a few examples. Following cooling and solids removal, CO_2 and/or H_2S must be removed. There are many proven industrial techniques available for removing CO_2 and H_2S.

In addition to the gas cleaning equipment just described, facilities must also be provided for the treatment of liquid and solid waste streams and recovery of ammonia and hydrocarbon by-products. Included in these facilities are a primary water treatment unit, a gas liquor treatment unit, an ammonia still, coal and by-product storage facilities, and in the case of medium Btu gasification, an oxygen plant.

3.8.1.1c High-Btu Gasification

High Btu gasification is the process by which coal is converted to a high-Btu gas (900-1000 Btu/ft^3) called substitute natural gas, SNG. SNG can be freely substituted for natural gas and transported in the existing maze of natural gas pipelines which cross the U.S. Unfortunately, a commercial size plant has not yet been built in the U.S.

However, several designs have been proposed and some are in the pilot and demonstration plant stage. Candidate systems for the production of SNG include those gasifiers discussed in Section 3.8.1.1b as being capable of producing a high-Btu gas (See Table 3-73) plus several hydrogasifiers such as the Institute for Gas Technology

HYGAS® process, the Bituminous Coal Research BI-GAS process, the U.S. Bureau of Mines Hydrane process and others.

In order to define emissions, energy requirements, and other residual impacts, specific processes must be analyzed. To this end, the Lurgi Process and Synthane Process have been selected as examples to quantify residual information associated with the production of SNG.

All high-Btu gasification processes include the following steps:

1) coal pretreatment
2) gasification
3) cooling and solids removal
4) catalytic shifting
5) acid gas removal
6) sulfur recovery
7) catalytic methanation
8) product drying and compressing.

In addition to the above facilities, an auxiliary boiler, a steam superheater, a water treatment unit, oxygen plant and by-product storage facilities are required. While specific operating conditions are assumed for some of the processing units, it is felt that there are other alternatives available which could meet the process requirements. Moreover, these alternatives should exhibit environmental impacts similar to the conditions assumed. Figure 3-22 and Figure 3-23 show the typical overfall flow diagrams for the Lurgi and Synthane processes analyzed here.

As is the case with low- and medium-Btu gasification, the distinguishing characteristic between high Btu gasification

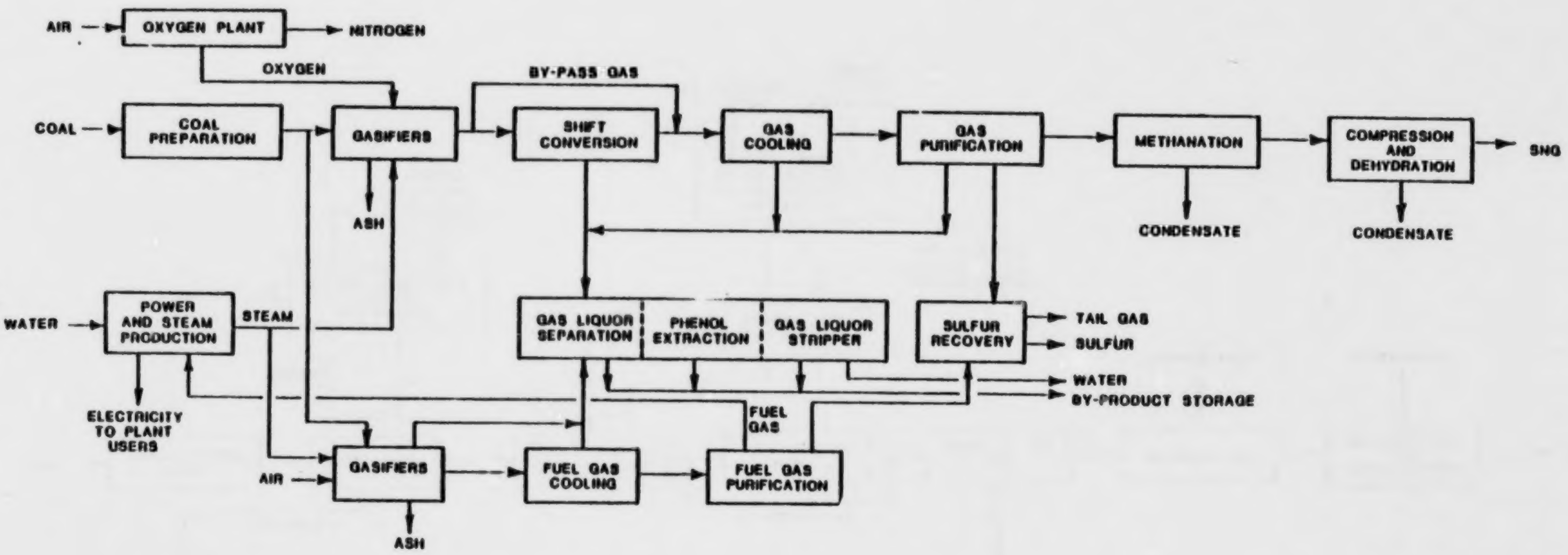
AIR
OXYGEN PLANT
NITROGEN
OXYGEN
BY-PASS GAS
COAL
COAL PREPARATION
GASIFIERS
SHIFT CONVERSION
GAS COOLING
GAS PURIFICATION
METHANATION
COMPRESSION AND DEHYDRATION
SNG
ASH
CONDENSATE
CONDENSATE
WATER
POWER AND STEAM PRODUCTION
STEAM
GAS LIQUOR SEPARATION
PHENOL EXTRACTION
GAS LIQUOR STRIPPER
SULFUR RECOVERY
TAIL GAS
SULFUR
WATER
BY-PRODUCT STORAGE
ELECTRICITY TO PLANT USERS
FUEL GAS
AIR
GASIFIERS
FUEL GAS COOLING
FUEL GAS PURIFICATION
ASH

Figure 3-22. Overall lurgi high-Btu gasification flow diagram.

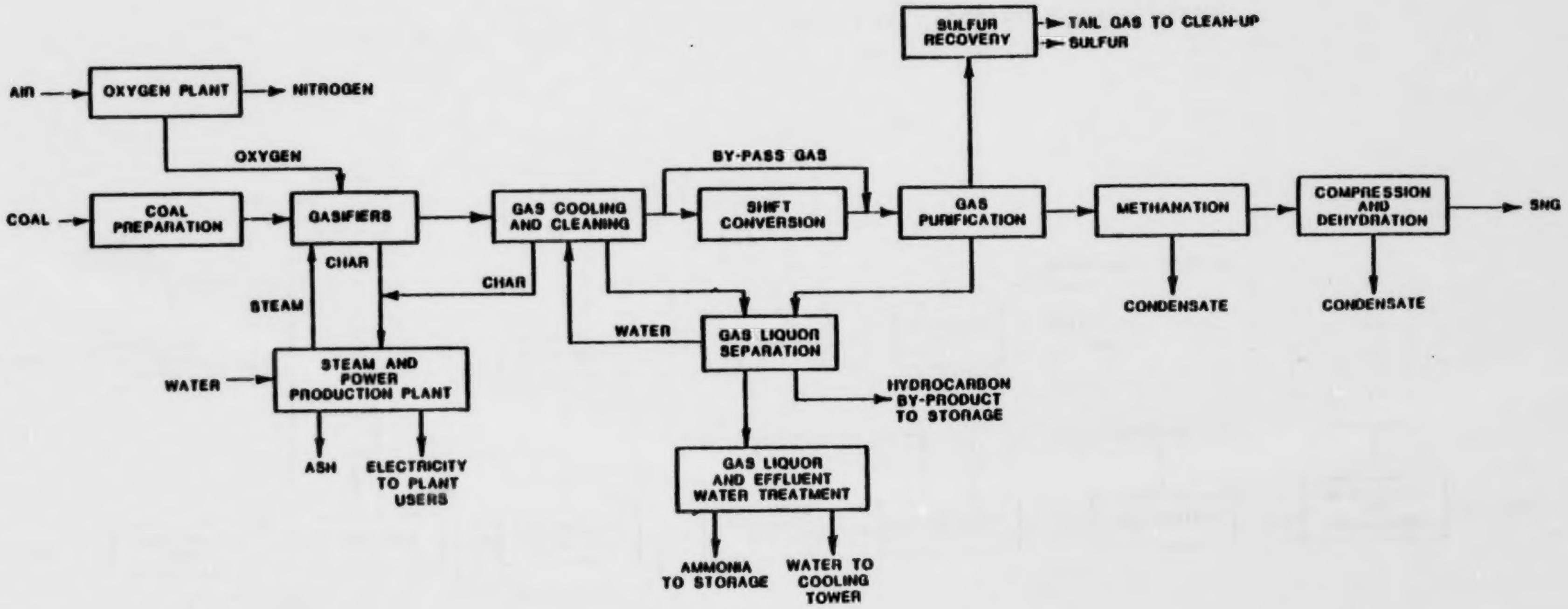
AIR
OXYGEN PLANT
NITROGEN
OXYGEN
COAL
COAL PREPARATION
GASIFIERS
CHAR
STEAM
CHAR
WATER
STEAM AND POWER PRODUCTION PLANT
ASH
ELECTRICITY TO PLANT USERS
GAS COOLING AND CLEANING
WATER
BY-PASS GAS
SHIFT CONVERSION
GAS LIQUOR SEPARATION
HYDROCARBON BY-PRODUCT TO STORAGE
GAS LIQUOR AND EFFLUENT WATER TREATMENT
AMMONIA TO STORAGE
WATER TO COOLING TOWER
GAS PURIFICATION
SULFUR RECOVERY
TAIL GAS TO CLEAN-UP
SULFUR
METHANATION
CONDENSATE
COMPRESSION AND DEHYDRATION
CONDENSATE
SNG

Figure 3-23. Overall synthane high-Btu gasification flow diagram.

processes is the mechanism and equipment used for gasification of the coal. All other process units are essentially the same. The following sections, therefore, present the design and operating conditions used within this phase of the Lurgi and Synthane processes. A fourth section describing the remaining common processing steps for the designs is then presented.

Lurgi Gasifier

Before coal can be fed to the Lurgi gasifier it must be reduced in size. Noncaking or slightly caking coal is crushed to two coal sizes, 8 mm x 2 mm and 45 mm x 8 mm. A mixture of the two coal sizes is fed to the top of the gasifier through a lock hopper. Cooled synthesis gas from the gas cooling area is used as the pressurizing fluid to bring the lock hopper up to the 445 psig operating pressure of the gasifier. The gasifier may be designed to operate anywhere between 300 and 500 psi.[1] After the lock hopper has emptied, the remaining high pressure lock gases are collected in a holding tank, recompressed and combined with the main process stream in the gas cooling area. The residual atmospheric lock gas that is displaced when the hopper receives its next coal charge is directed to the incineration area for disposal.

The crushed coal is fed into the gasifier and distributed by a revolving grate. The Lurgi gasifier is a moving bed, steam-oxygen gasifier. The main operating difference between the high-Btu Lurgi gasifier and the low-Btu gasifier is the purity of the oxygen feed. The low-Btu gasifier uses air while the high-Btu gasifier uses oxygen.

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[1] U.S. Federal Power Commission, Synthetic Gas-Coal Task Force. Final Report: The Supply-Technical Advisory Task Force-Synthetic Gas-Coal. Washington, D.C., Federal Power Commission, 1973.

The steam and oxygen are injected at the bottom of the gasifier and are distributed through a second revolving grate which also provides bed support and regulates the ash removal rate. Ash is removed from the gasifier by a lock hopper and water quenched. Figure 3-24 shows the Lurgi gasifier. Figure 3-25 presents a schematic of the Lurgi gasifier showing the various reaction zones.

The steam and oxygen react with char in the reaction zone of the gasifier according to Equations 3-8 and 3-9 to produce heat and a medium-Btu gas. As this hot gas rises through the downward moving coal bed, the coal entering the gasifier is devolatilized according to Equation 3-7. The hot gas mixture leaving the top of the reactor is called a synthesis gas. The temperature at the top of the gasifier is about 1000°F while the temperature at the bottom is about 1800°F.

$$\text{Coal} \rightarrow CH_4 + \text{Char} + \text{Heat} \qquad (3\text{-}7)$$

$$C + H_2O + \text{Heat} \rightarrow CO + H_2 \qquad (3\text{-}8)$$

$$2C + O_2 \rightarrow 2CO + \text{Heat} \qquad (3\text{-}9)$$

The char may react according to Equation 3-10 to produce methane directly. The synthesis gas may also undergo various other reactions such as Equations 3-11 and 3-12 to yield CO_2 and methane.

$$C + 2H_2 \rightleftarrows CH_4 + \text{Heat} \qquad (3\text{-}10)$$

$$CO + H_2O \rightleftarrows CO_2 + H_2 + \text{Heat} \qquad (3\text{-}11)$$

$$CO + 3H_2 \rightleftarrows CH_4 + H_2O + \text{Heat} \qquad (3\text{-}12)$$

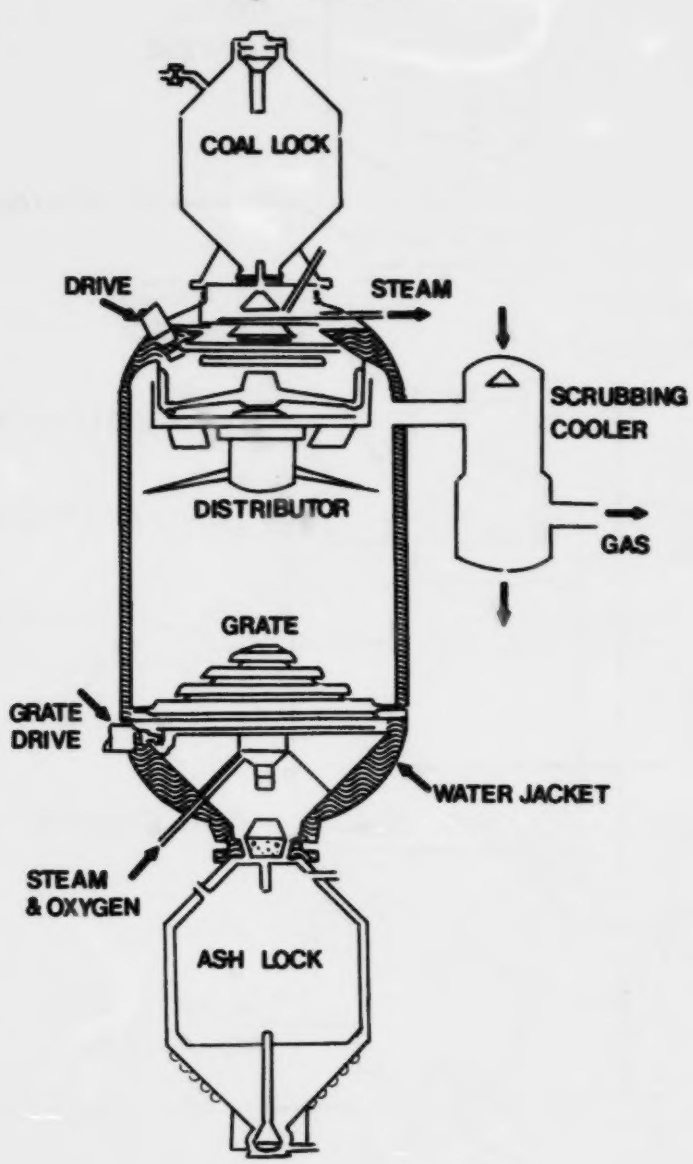
FEED COAL
COAL LOCK
DRIVE
STEAM
SCRUBBING
COOLER
DISTRIBUTOR
GAS
GRATE
GRATE
DRIVE
WATER JACKET
STEAM
& OXYGEN
ASH LOCK

Figure 3-24. Schematic of a Lurgi Gasifier.

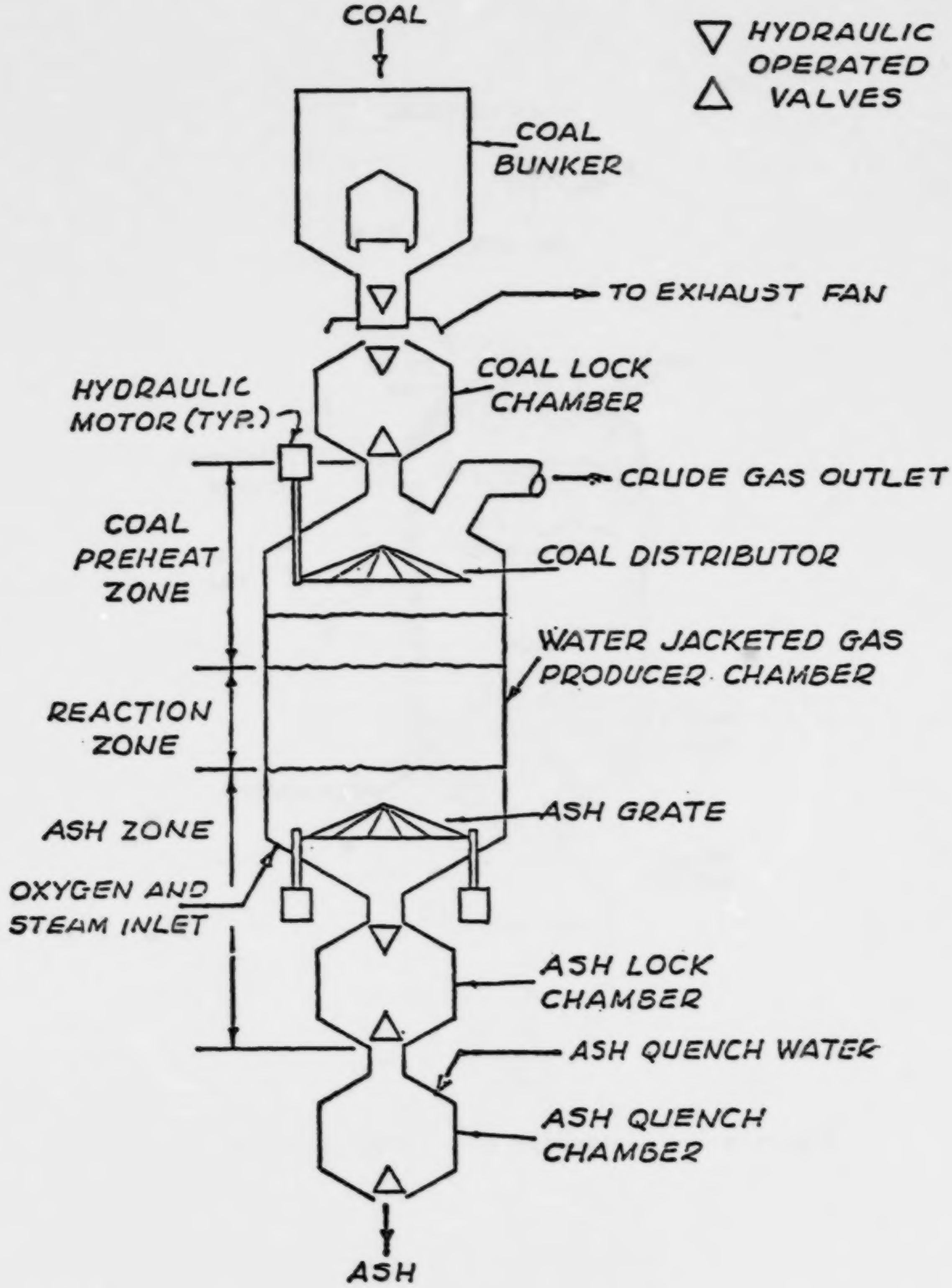
COAL
▽ HYDRAULIC OPERATED
△ VALVES
COAL BUNKER
TO EXHAUST FAN
COAL LOCK CHAMBER
HYDRAULIC MOTOR (TYP.)
CRUDE GAS OUTLET
COAL PREHEAT ZONE
COAL DISTRIBUTOR
WATER JACKETED GAS PRODUCER CHAMBER
REACTION ZONE
ASH GRATE
ASH ZONE
OXYGEN AND STEAM INLET
ASH LOCK CHAMBER
ASH QUENCH WATER
ASH QUENCH CHAMBER
ASH

Figure 3-25. Schematic diagram of lurgi gasifier.

These reactions illustrate that the coal is initially subjected to a reducing atmosphere. It subsequently enters an oxidizing atmosphere as discussed above. The effect of these regimes is discussed under environmental considerations relative to the fate of trace compounds.

Synthane Gasifier

In the Synthane Process, coal sized to pass through a 200 mesh screen is mixed with steam and oxygen in a fluidized bed pretreatment pressure vessel at 1,000 psi and 800°F[1] where the coal is partially devolitized and its caking tendency destroyed. About 12% of the total steam and oxygen necessary for the Synthane process is fed to the pretreater. From this pretreatment stage, the coal and gases enter the top of the gasifier. A schematic of the Synthane Gasifier is presented in Figure 3-26.

The Synthane Process utilizes a two-stage, fluidized bed gasifier. The coal enters the hydrogasification stage of the gasifier and then the gasification section. Both of these stages operate as a fluidized bed. At the bottom of the gasifier, steam and oxygen are injected and char and ash removed. The steam, oxygen, and char react according to Equations 3-13 to 3-16 producing a synthesis gas. The gasification stage operates at 1750-1850°F and the hydrogasification stage at 1100-1450°F. The entire gasifier is under 600-1000 psi pressure. The reactions which take place in the gasifier are as follows:

$$\text{Coal} \rightarrow CH_4 + \text{Char} + \text{Heat} \qquad (3\text{-}13)$$

$$C + 2H_2 \rightarrow CH_4 + \text{Heat} \qquad (3\text{-}14)$$

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[1] University of Oklahoma, Science and Public Policy Program. Energy Alternatives: A Comparative Analysis. Washington Government Printing Office, 1975.

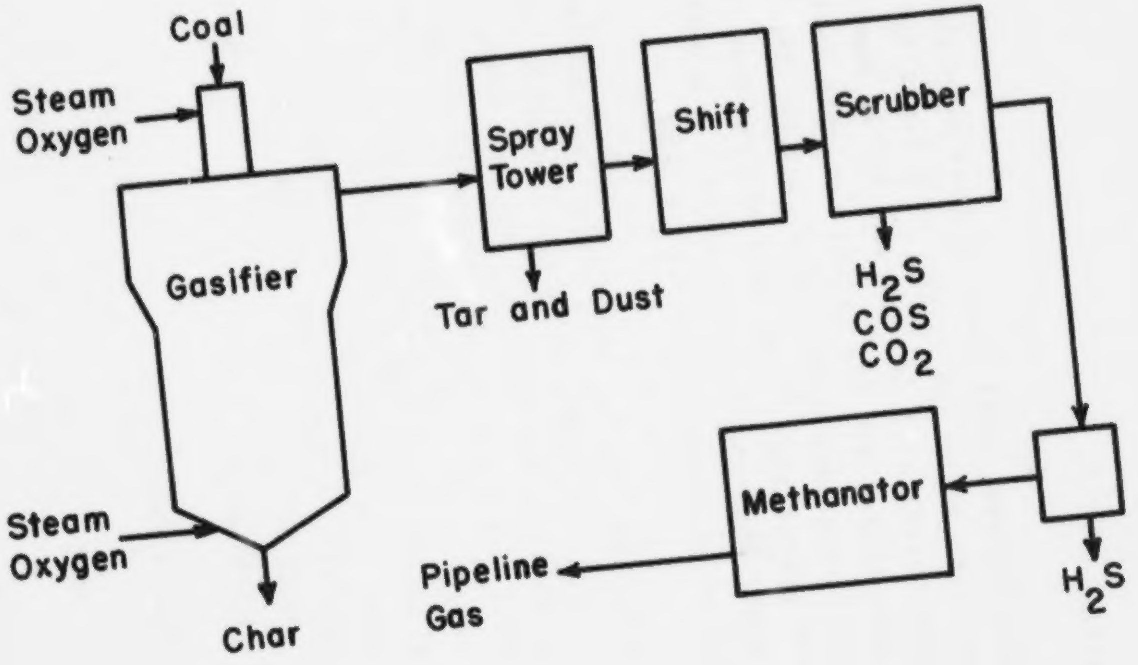
Coal
Steam
Oxygen
Gasifier
Steam
Oxygen
Char
Spray
Tower
Tar and Dust
Shift
Scrubber
H_2S
COS
CO_2
Methanator
H_2S
Pipeline
Gas

Figure 3-26. Schematic diagram of the Synthane Process.

Source: Adapted from BuMines, 1974c: 11.

$$C + H_2O + Heat \rightarrow CO + H_2 \qquad (3\text{-}15)$$

$$2C + O_2 \rightarrow 2CO + Heat \qquad (3\text{-}16)$$

Common Processing Steps

This section describes the remaining process units in a high-Btu gasification facility. The starting point is the synthesis gas from the gasifier. Synthesis gas produced during coal gasification can contain dust, coal fines, carbon char, tars, oils, and phenols. To prevent plugging of the shift reactor and poisoning of downstream catalysts, the synthesis gas is cleaned of all solids. Conventional processing equipment can be used to accomplish this, but may have to be refined to ensure essentially 100% solids removal. Typical methods would include dry cyclones, wet cyclones, venturi scrubbers, quenchers, and bag filters.[1]

In addition to solids removal before the shift reactor, the synthesis gas is cooled to 550-650°F. This is necessary to avoid excessively high temperatures in the shift reactor due to the exothermic water gas reaction. The use of water wash columns, direct quenches, venturi scrubbers and/or heat exchangers has been proposed for cooling the synthesis gas prior to its entering the shift reactor.

Synthesis gas is upgraded to SNG by the catalytic methanation reaction shown below:

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[1] Radian Corporation. A Western Regional Energy Development Study, Final Report, 4 vols. Austin, Tex.: Radian Corp., 1975.

$$CO + 3H_2 \rightleftarrows CH_4 + H_2O + Heat \qquad (3\text{-}17)$$

This requires a 3:1 ratio of hydrogen to carbon monoxide. However, this ratio in most synthesis gases is about 1:1 or lower. To obtain the desired ratio of H_2:CO, steam is added to the synthesis gas and the gas is catalytically shifted according to the water/gas reaction given by Equation 3-18 to give the 3:1 ratio.

$$CO + H_2O \rightleftarrows CO_2 + H_2 + Heat \qquad (3\text{-}18)$$

The water/gas reaction has been proven for several industrial applications, for example, the production of ammonia. However, in the ammonia system, the CO content of the gas is much lower than that found in coal gasification synthesis gas. Work has been done and still needs to be done to develop new shift reactor catalysts and methods of operating the shift reactor.

The need to find a new catalyst arises because of the reducing tendencies of the high CO content of the synthesis gas. This causes the metal oxide catalysts employed to be reduced to the elemental metal which will then catalyze the methanation reaction, Equation 3-17. This reaction is highly exothermic and will cause hot spots in the reactor bed and damage the catalyst. To offset the reducing effect of CO, large quantities of steam, which has an oxidation effect, are added. However, steam has adverse effects on the mechanical strength of the catalyst. A 1:1 ratio of steam to dry gas has been recommended by catalyst manufacturers as the best shift reactor feed.[1]

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[1] Air Products and Chemicals, Inc. Engineering Study and Technical Evaluation of the Bituminous Coal Research, Inc. Two-Stage Super Pressure Gasification Process. Washington: Office of Coal Research, undated.

The sulfurous compounds, to be removed during acid-gas treatment, are generated during the gasification of the coal. A primary purpose of gasification processes is to convert a high-sulfur fuel, such as coal, into a low-sulfur energy source, such as substitute natural gas. The sulfur which occurs naturally in the feedstock, therefore, must be eliminated from the system.

The primary sulfur compound which exists in the synthesis gas stream is hydrogen sulfide (H_2S). When carbon monoxide is present in the process gas stream, carbonyl sulfide (COS) will also be generated. If a portion of the process exists at relatively high temperatures, carbon disulfide (CS_2) will be formed. If the hydrogen and carbon monoxide concentrations in the primary reaction stage are approximately equal, the thermodynamically expected carbonyl sulfide concentration is about 1/30 of the hydrogen sulfide concentration, and the carbon disulfide concentration will be even lower. As will be shown later, however, hydrogen sulfide is more readily removed from the process gas stream than COS or CS_2. Therefore, the processing conditions which affect the manufacture and conversion of COS and CS_2 must be examined to determine the overall pollutant discharge from the facility.

Other forms of sulfur such as organic sulfides, mercaptans, and thiophenes, are also produced in the primary reaction step during the devolitization of coal. These heavier sulfur compounds will be collected with the tars and oils from the process and can be converted to H_2S if the tars and oils are hydrodesulfurized. The H_2S, COS, and CS_2 are the primary sulfur types to be found in the synthesis gas as it reaches the acid-gas treatment section of the facility.

The acid-gas containing these compounds is generally removed from the product gas by physical absorption with an organic solvent. In these processes, the product gas undergoes countercurrent scrubbing at high pressures with a solvent which will absorb the acid-gas. The solvent is then stripped of the acid-gas and recirculated to the adsorbers. Some of the well-known solvent-based processes are defined in Table 3-74.

In addition to these solvent-based processes there are other systems which could be used for acid-gas removal. These include processes which remove the gas by reactions with alkaline salts or amines or by indirect oxidation. For the analysis reported herein, it is assumed that the solvent based Rectisol process is used in the Lurgi process and the Benfield hot carbonate process is used in the Synthane process.

The off-gases from these acid-gas removal processes must be further treated for sulfur removal before they can be vented to the atmosphere. This is generally accomplished by a Claus and/or a Stretford unit. In a Claus unit, the sulfur is recovered as elemental sulfur by first oxidizing one third of the H_2S according to Equation 3-19. The SO_2 from this reaction is then reacted with the remaining H_2S according to Equation 3-20 to produce elemental sulfur and water.

$$2H_2S + 3O_2 \rightleftarrows 2SO_2 + 2H_2O \qquad (3\text{-}19)$$

$$2H_2S + SO_2 \rightleftarrows 3S + 2H_2O \qquad (3\text{-}20)$$

The Claus process is discussed in more detail in Section 7.4.1.3 where its use in natural gas processing is described. In the Stretford unit, the H_2S in the acid-gas is oxidized directly to elemental sulfur and water by utilizing a vanadium catalyst. For this analysis, it is assumed that the Stretford unit is used

TABLE 3-74. SOLVENT BASED PROCESSES

Process	Developer	Solvent	Typical Treated Gas Purity		Attainable Treated Gas Purity	
			H_2S	CO_2	H_2S	CO_2
Purisol	Lurgi	N-Methyl-2 pyrrolidone	4 ppm	2 - 3%	2 ppm	10 ppm
Fluor	Fluor	Propylene carbonate	>4 ppm	1 - 2%		
Selexol	Allied	Dimethyl ether polyethylene glycol	4 ppm	2 - 4%		0.5%
Rectisol	Lurgi	Methanol	3 ppm	60 ppm		10 ppm
Sulfinol	Shell	Tetrahydrothiopene 1-1 dioxide (Sulfolene) plus diisopropanolamine (DIPA)	4 ppm	<0.5%		200 ppm

for acid-gas cleaning with incineration of the off-gas to remove hydrocarbons.

After the product gas has been treated for acid-gas removal by these processes, it must be catalytically methanated to yield pipeline quality SNG. The methanation reaction was given in Equation 3-17. This reaction is strongly exothermic, giving off 88,700 Btu/lb-mole. Two important considerations in the design of the methanator are 1) a heat removal technique to limit the gas exit temperature to around 850°F and 2) a suitable catalyst to methanate a feed stream that contains substantial carbon monoxide.

Several possible systems for methanation have been proposed. The first involves spraying the catalyst on the outside of tubes, with cooling fluid being circulated inside the tubes. The synthesis gas passes over the catalyst and undergoes methanation. The heat of reaction liberated is carried away by the cooling fluid. Problems have occurred in retaining catalyst activity for sufficient periods of time. A second method employs a system of catalytic reactors with intercooling equipment. A major drawback to this method arises because the location of the intercoolers changes during startup, shutdown, and periods of reduced gas flow. A third system utilizes a large recycle stream of cooled product to increase the heat capacity of the gas stream. This method has economic ramifications due to the large recirculation rate of product gas. Methanation reactors have been proposed which use a fixed or fluidized catalyst bed.

The methanation reaction is a well-known reaction with widespread use in the ammonia synthesis industry. However, the coal gasification synthesis gas which must be methanated is considerably more concentrated with CO and H_2 than in any previous application. Studies are needed to demonstrate the reliability of the methanation catalyst. Catalysts proposed for use contain nickel and molybdenum.

The SNG product from the methanator contains water which must be removed to meet pipeline specifications. Technology in this area is industrially proven and any of several methods are acceptable, such as glycol absorption. The dry SNG is then compressed and is available for use, transport, or storage.

Many of the processing units of a SNG-from-coal plant are new technology and have yet to be industrially proven. In addition, the water-gas shift reactor and methanation reactor have not been proven for handling streams with carbon monoxide and hydrogen content as great as those found in gasification synthesis gases.

In addition to the processing equipment discussed previously, both the Synthane and Lurgi facilities require steam and electricity. The steam is generally produced on-site with high-pressure boilers and steam superheaters. These steam production facilities can be fired by coal or other externally supplied fuel or by synthetic fuel generated at the facility. The Lurgi facility considered here is assumed to burn a low-Btu fuel gas produced on-site. The Synthane facility is assumed to burn char produced in the gasifier for steam production.

The electricity necessary to operate the facilities can either be purchased or produced on-site. Electricity generated on-site is generally produced through the use of turbines and generators. The facilities 'considered here use this approach: the Lurgi facility uses gas turbines fired with low-Btu fuel gas and the Synthane uses steam turbines with steam provided by the utility boiler.

3.8.1.2 Input Requirements

Input Requirements are discussed for Lurgi and Synthane facilities producing 250 million standard cubic feet per day (250 MMscfd) of high-Btu gas. When necessary to assume values in order to quantify the inputs, i.e., manpower requirements, material and equipment needed, capital costs, water requirements, land usage, or ancillary energy, these assumptions are stated. The following sections will address each of the above inputs for the 250 MMscfd facilities.

The inputs and outputs associated with these facilities will vary somewhat with the characteristics of the coal which is used. Where necessary, the coal composition used in this analysis is that shown in Table 3-75 for coal produced near Colstrip, Montana. This coal is consumed in the gasification processes at a rate of 24,520 TPD at the Lurgi facility and 21,530 TPD at the Synthane facility. The composition of the SNG produced by the processes is shown in Table 3-76. The heat content of the SNG is approximately 950 Btu/scf for each process. The difference in coal feed rates between the two processes is attributable to differences in process efficiency and in the overall mix of products from each process.

3.8.1.2a Manpower Requirements

There are two labor phases required for all facilities: the construction phase and the operating phase. The Bechtel Corporation has estimated the manpower required for construction and operation of a 250 MMscfd Lurgi high-Btu gasification facility.[1] It is assumed that these manpower requirements are roughly the same for the Synthane high-Btu gasification facility. Table 3-77 presents the construction manpower and the proper timing sequence

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[1] Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

TABLE 3-75. COAL ANALYSIS - COLSTRIP, MONTANA

Rosebud County
Fort Union Region
Colstrip Field

Proximate Analysis, %

Moisture: 22.3 - 25.6
Volatile: 36.8 - 41.4
Fixed C: 47.7 - 54.4
Ash: 8.8 - 11.1

Ultimate Analysis, %

Ash: 8.8 - 11.1
S: 0.8 - 1.2
H : 3.8 - 5.0
C: 62.9 - 70.6
N: 1.0 - 1.1
O: 13.0 - 20.1

Btu/lb (as received): 7,910 - 9,290
Btu/lb (dry): 10,390 - 12,040

Source: Evaluation of Low-Sulfur Western Coal. EPA-650/2-75-046. May 1975.

TABLE 3-76. SNG COMPOSITION

Component	Lurgi SNG[1] (Vol. %)	Synthane SNG[2] (Vol. %)
CH_4	92.92	94.3
CO_2	1.81	0.8
CO	0.01	0.0
H_2	4.16	2.0
N_2	1.09	2.9
H_2O	0.01	0.0
Total	100.00	100.0

[1] Radian Corporation. Characterization of Waste Effluents From A Lurgi Gasification Plant, Technical Note. Austin, Tex.: Radian Corp., 1975.

[2] Radian Corporation. Characterization of Waste Effluents From A Synthane Gasification Plant, Technical Note. Austin, Tex.: Radian Corp., 1976.

TABLE 3-77. SCHEDULE OF MANPOWER RESOURCES (MAN-YEARS) REQUIRED TO CONSTRUCT A 250 MMscfd COAL GASIFICATION PLANT

Skill			Year		
	1	2	3	4	5
Chemical Engineers	3	42	68	57	27
Civil Engineers	4	49	79	66	32
Electrical Engineers	4	45	74	61	29
Mechanical Engineers	5	61	99	82	39
Other Engineers	1	17	27	22	11
Total Engineers	17	214	348	289	138
Total Designers & Draftsmen	12	155	252	210	100
Total Supervisors & Managers	3	41	67	55	26
Total Technical	32	410	666	554	265
Total Non-Tech (Non-Manual)	4	55	81	49	19
Pipefitters	0	49	656	1410	802
Pipefitter/Welders	0	17	234	503	285
Electricians	0	16	211	453	258
Boilermakers	0	7	100	214	122
Boilermaker/Welders	0	1	18	38	21
Iron Workers	0	6	82	176	100
Carpenters	0	10	135	289	165
Operating Engineers	0	10	129	277	158
Other Major Skills	0	3	47	101	57
Total Major Skills	0	119	1611	3461	1969
Other Craftsmen	0	1	18	38	21
Total Craftsmen	0	121	1629	3499	1991
Total Teamsters & Laborers	0	23	316	680	387
GRAND TOTALS	36	609	2692	4782	2662

Source: Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

to efficiently build a gasification plant. Table 3-78 represents the manpower required to operate a 250 MMscfd facility.

3.8.1.2b Materials and Equipment

Table 3-79 lists the major materials and equipment required to construct a 250 MMscfd gasification plant.

3.8.1.2c Economics

Bechtel's "Energy Supply Planning Model"[1] gives the total capital costs of a 250 MMscfd coal gasification plant as $750 million (third-quarter-1974 dollars). Bechtel has also estimated annual utility costs as $1 million. Using the manpower figures in Table 3-78 and assuming an average annual wage of $15,000, total operating costs are $9.8 million per year.

3.8.1.2d Water Requirements

Water must be supplied to the gasification facilities to replace the water lost and/or used in the coal conversion. The primary source of water loss is evaporation from the cooling tower, evaporation ponds, and processing equipment. Water is also used in the process. For example, both the gasifier and the shift converter consume significant quantities of water in reactions. The make-up water requirements for the 250 MMscfd Lurgi plant are estimated to be 5742 gpm (9262 acre-ft/yd)[2,3] while water requirements for a 250 MMscfd Synthane plant

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[1] Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

[2] U.S. Dept. of the Interior, Bureau of Reclamation, Upper Colorado Region, El Paso Gasification Project, San Juan County, N.M. DES-74-77. 1974.

[3] Radian Corporation. Characterization of Waste Effluents From A Lurgi Gasification Plant, Technical Note. Austin, Tex.: Radian Corp., 1975.

TABLE 3-78. MANPOWER RESOURCES REQUIRED FOR OPERATION AND MAINTENANCE OF A 250 MMscfd COAL GASIFICATION PLANT

Skill	Number Required
Chemical Engineers	16
Civil Engineers	4
Electrical Engineers	2
Mechanical Engineers	6
Other Engineers	1
Total Engineers	29
Total Designers & Draftsmen	3
Total Supervisors & Managers	5
Total Other Technical	19
Total Technical	56
Total Non-Tech (Non-Manual)	46
Pipefitters	28
Electricians	16
Boilermakers	10
Carpenters	7
Other Operators	212
Welders, Unclassified	19
Other Major Skills	83
Total Major Skills	375
Other Craftsmen	46
Total Craftsmen	421
Total Teamsters & Laborers	66
GRAND TOTAL	589

Source: Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

TABLE 3-79. SELECTED MAJOR MATERIALS AND EQUIPMENT REQUIRED FOR CONSTRUCTION OF A 250 MMscfd COAL GASIFICATION PLANT

Resource	Number
Refined Products (Tons)	225
Cement (Tons)	30
Ready Mixed Concrete (Tons)	180,000
Pipe & Tubing (Less than 24" D) (Tons)	45,000
Pipe & Tubing (24" D & Greater) (Tons)	13,000
Structural Steel (Tons)	14,000
Reinforcing Bars (Tons)	3,300
Valves (24" D & Greater) (Items)	2,000
Valves (24" D & Greater) (Tons)	2,000
Steam Turbogenerator Sets (1000 HP)	70
Pumps & Drives (100 HP) (Items)	250
Pumps & Drives (100 HP) (Tons)	2,000
Compressors & Drives (1000 HP) (Items)	23
Compressors & Drives (1000 HP) (Tons)	4,300
Heat Exchangers (1000 Sq. Ft. Surface)	380
Pressure Vessels (1½" Plate) (Tons)	19,700
Boilers (1,000,000 Btu/Hr)	25,000

Source: Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

are estimated to be 18,000 gpm (29,036 acre-ft/yr).[1] These values, of course, will vary with allowances for water reuse and conservation designed into any specific facility.

3.8.1.2e Land Requirements

Land requirements for an SNG from coal plants can include areas for processing equipment, coal storage, solar evaporation ponds and solid waste disposal. It has been estimated that 165 acres are required for a plant capable of producing 236 x 10^6 scf/day of SNG.[2] On a 250 x 10^6 scf/day basis, plant land requirements are approximately 175 acres. From The National Atlas of the United States, the average class A pan evaporation for the western states is approximately 50 in/yr. With the assumption that true evaporation from a pond saturated with dissolved solids is 50% of pan data, 25 in/yr of pond evaporation is available. Based on 400,000 lb/hr of liquid wastes to the evaporation pond, 630 acres of evaporation ponds are required to handle the liquid wastes of a 250 x 10^6 scf/day plant in these states. The total land required, therefore, is approximately 800 acres.

3.8.1.2f Ancillary Energy

Since the gasification facilities considered in this analysis will be self-sustaining with process heat and electricity requirements generated on-site, the ancillary energy requirements are zero.

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[1] Kalfadelis, C. D. and E. M. Magee. Evaluation of Pollution Control in Fossil Fuel Conversion Processes; Gasification. Section I: Synthane Process, final report. EPA 650/2-74-009b. Linden, N.J., Esso Research & Engineering Co., 1974.

[2] Air Products and Chemicals, Inc. Engineering Study and Technical Evaluation of the Bituminous Coal Research, Inc. Two-Stage Super Pressure Gasification Process. Washington: Office of Coal Research, undated.

3.8.1.3 Outputs

The outputs associated with Lurgi and Synthane gasification facilities are discussed in the following sections. The air, water and solid waste effluents for the Lurgi facility were determined from data reported by El Paso Natural Gas for a proposed 288 MMscf/day gasification facility.[1,2] This data was scaled to a 250 MMscf/day facility by assuming outputs were directly proportional to SNG production. Where process changes are assumed or data is obtained by analysis of a different facility, such variations are noted in the text.

The analysis of the Synthane facility is based on laboratory gasifier data[3] as incorporated into the design of a 255 MMscfd facility.[4] Data for this facility was scaled to the 250 MMscfd facility by assuming outputs are directly proportional to SNG production. Where assumptions were made with regard to this facility, they are noted in the text.

3.8.1.3a Air Emissions

One potential air emission generated by both coal gasification facilities is particulate emissions from solids handling

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[1] U.S. Department of the Interior, Bureau of Reclamation, Upper Colorado Region. El Paso Gasification Project, San Juan County, N.M. DES-74-77. 1974.

[2] El Paso Natural Gas Co., Application of El Paso Natural Gas Co. for a Certificate of Public Convenience and Necessity. Docket No. CP73-131. El Paso, Tex., 1973.

[3] M. W. Kellogg Co. Engineering Evaluation and Study of the Bureau of Mines "Synthane" Process, Draft report. Contract No. 30101374. Unpublished, 1970.

[4] Radian Corporation. Characterization of Waste Effluents From A Synthane Gasification Plant, Technical Note. Austin, Tex.: Radian Corp., 1976.

operations. The facilities considered here are designed to minimize these emissions by the following methods:

1) Coal grinding and screening operations are enclosed and wet scrubbers are used where necessary.

2) Coal piles are protected from wind erosion by wind barriers and proper pile orientation.

3) Dust suppression sprays are used at coal transfer points where necessary.

4) Dust suppression and collections systems are used on all coal storage bunkers and ash locks.

The fugitive dust generated at the facilities is suppressed at other sources by pavement and surface sprays. Proper maintenance of these systems should reduce particulate emissions from these sources to a negligible level.

In addition to these coal handling emissions, the Synthane facility has a potential of producing emissions from coal dryers. The dryers may be necessary since the Synthane process will operate more efficiently with a coal of less than 14% moisture and the coal may have a higher moisture content (e.g., Colstrip, Montana, coal ranges from 22.3 to 25.6% moisture). It is assumed for this analysis, however, the the coal is dried by using the waste heat in the combustion stack gases.[1] Therefore, no additional combustion is necessary and any particulates generated are assumed to be controlled by a high efficiency electrostatic precipitator. The emissions, therefore, are negligible.

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[1] Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supplied by Emerging Technologies, Phase 2, Draft final report, Tasks 1-11. HIT-573, Contract No. EQC 308. Columbia, Md., 1973.

The gasifier coal lock is a second potential source of air emissions at these facilities. The coal lock allows introduction of air into the pressurized gasifier by first being charged with coal at atmospheric pressure, closing the vessel, pressurizing with product gas to gasifier pressure, charging the coal to the gasifier and then being depressurized. A potential for air emissions exists when the gas used to pressurize the coal lock is released during depressurization. However, in most current plant designs, the gas used in this process is collected in a holding tank, recompressed and combined with the main process stream in the gas cooling area. The residual atmospheric lock gas that is displaced when the next coal charge is introduced is directed to the incineration area for disposal. The emissions, therefore, are limited to negligible levels.

Process vent and stack gases are another source of air emissions from these facilities. The potential sources of air emissions within this category are essentially limited to off-gases from oxygen production and sulfur recovery. The quantity of contaminants emitted from the oxygen production area is considered to be negligible for both facilities. As was discussed previously, the sulfur recovery system in the Lurgi design consists of a Rectisol solvent adsorption acid-gas removal process followed by a Stretford sulfur recovery system. In addition, it is assumed that the sulfur recovery vent gases are incinerated in order to minimize hydrocarbon emissions. It is also assumed that this incineration converts all hydrocarbons to CO_2 and water and all sulfur compounds to SO_2, CO_2 and water.

The Synthane process uses the Benfield process for acid-gas removal to reduce the H_2S concentration in the SNG to about 3 vppm. The acid gas streams produced by depressurization of the contaminated condensate and regeneration of the Benfield solution are sent to a Stretford unit for removal of H_2S and recovery of elemental sulfur. The sulfur content of the acid gases is reduced to about 1 vppm. The off-gas from the Stretford oxidizer is combined with the desulfurized gas for disposal by incineration. This incineration step reduces the CO and hydrocarbons by 99+%.

Another possible source of air emissions from these facilities is the cooling towers. The gaseous effluents from the cooling towers consist of water vapor, entrained water and any gases that are air stripped from the recirculating cooling water. The cooling towers at the Lurgi facility are designed to dissipate 1.1×10^9 Btu/hr with a water recirculation rate of 69.9×10^6 lb/hr. The cooling towers at the Synthane facility are designed to dissipate 3.7×10^9 Btu/hr with a water recirculation rate of 148×10^6 lb/hr.

The major source of make-up water to the cooling system is treated oily gas liquor. Since this stream was originally in intimate contact with unpurified synthesis gas, it can contain any of the synthesis gas constituents as dissolved or suspended compounds. In the gas liquor treating areas the gas liquor contaminants are removed to very small or trace concentrations by separation and stripping processes. Therefore, the cooling system make-up water should be fairly clean with respect to dissolved or volatile components. However, 100% contaminant removal in the gas liquor treating areas cannot be expected and some air stripping of NH_2, H_2S, CO_2 and trace organics and inorganics is possible in the cooling tower.

As can be seen from the previous discussion, the various processes used in the gasification train do not produce significant quantities of air emissions. The major source of these emissions, therefore, is the stack gases from production of steam for process use and electricity generation. As was discussed previously, the Lurgi facility is assumed to utilize steam boilers and gas turbines fired by a low-Btu fuel gas produced on-site. In addition, a fuel gas fired steam superheater and free standing boiler provide high temperature steam and emergency steam capacity, respectively. Fuel gas is produced on-site at the rate of 12.2 MMscfh for these purposes. An analysis of this fuel gas is shown in Table 3-80. Since the boiler fuel is cleaned fuel gas, no particulate or sulfur dioxide control methods are required. NO_x emissions are controlled by combustion modifications such as low excess air firing and reduced peak flame temperatures.

The utilities for the Synthane facility are produced by combustion of gasifier char. This gasifier char is utilized at a rate of approximately 337,000 lb/hr as boiler fuel to produce steam for motive and process uses and for electricity production. A typical ultimate analysis of gasifier char is given in Table 3-81. Particulate emissions from the combustion of char are controlled by electrostatic precipitators while sulfur oxide emissions are controlled by limestone wet scrubbers. The EPA criteria pollutants present in the combustion gases are estimated from EPA emission factors.[1]

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[1] Environmental Protection Agency. Compilation of Air Pollutant Emission Factors, 2nd ed., with supplements. AP-42. Research Triangle Park, N.C., Feb. 1972, April 1973, July 1973, Sept. 1973, July 1974, Jan. 1975, Dec. 1975, Feb. 1976, April 1977.

TABLE 3-80. CLEANED FUEL GAS ANALYSIS

Component	Vol. %
CO_2	14.83
H_2S	0.01
C_2H_4	0.25
CO	17.44
H_2	23.25
CH_4	5.08
C_2H_6	0.38
N_2	38.51
H_2O	0.25

Heating Value = 194 Btu/scf (dry basis)
The fuel gas contains a small quantity of naphtha.

TABLE 3-81. ULTIMATE ANALYSIS OF GASIFIER CHAR

	Wt %
Carbon	55.9
Hydrogen	1.0
Oxygen	2.6
Nitrogen	0.7
Sulfur	4.0
Ash	35.8
	100.0

Heating Value ≅ 8700 Btu/lb

There are also fugitive air emissions at the Lurgi and Synthane gasification facilities. Fugitive air emissions from the facilities arise from leaks around pump seals, valves, flanges, storage facilities, etc. High pressures like those encountered in many of the processing operations also enhance fugitive leaks from equipment. For this study it is assumed that the fugitive emission losses are minimized by use of the best available control techniques, including mechanical seals on pumps, vapor recovery systems on storage facilities, etc. In addition, good maintenance practices help to minimize equipment leaks.

By-product storage losses are calculated using the method outline in API Bulletin No. 2523[1] and Compilation of Air Pollutant Emission Factors.[2] Vapor recovery systems with a 95% recovery efficiency are assumed to be used for emission control on the by-product hydrocarbon and ammonia storage vessels. Tables 3-82 and 3-83 list the input parameters for and the result of the storage emissions calculations for the Lurgi and Synthane facilities.

Estimates of the fugitive emissions from valves and pump seals are calculated from an emission factor of 0.5 lb/day for these pieces of equipment used in refinery services.[3] However, the pump seal emission factors were doubled if the pump handled

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[1] American Conference of Governmental Industrial Hygienists. Documentation of the Threshold Limit Values for Substances in Workroom Air, 3rd ed. Cincinnati, Ohio, 1971.

[2] Environmental Protectiona Agency. Compilation of Air Pollutant Emission Factors, 2nd ed., with supplements. AP-42. Research Triangle Park, N.C., Feb. 1972, April 1973, July 1973, Sept. 1973, July 1974, Jan. 1975, Dec. 1975, Feb. 1976, April 1977.

[3] Danielson, John A., comp. and ed. Air Pollution Engineering Manual, 2nd ed. AP-40. Research Triangle Park, N.C., EPA, Office of Air & Water Programs, 1973.

TABLE 3-82. BY-PRODUCT STORAGE EMISSION LOSSES - LURGI

Symbol		Naphtha	Tar Oil	Tar	Phenols	Ammonia
W	Liquid density, lb/gal	6.41	7.41	8.91	8.33	7.48
K	K factor	0.024	0.023	0.019	0.019	~0.023
V	Tank Capacity, bbl.	13,000(2)	27,000(2)	40,000(2)	5,500(2)	56,000(1)
P	Vapor pressure, psia	5.8	1.5	~0.5	~0.6	4.76
D	Tank diameter, ft.	48	62	76	36	90
H	Avg. Vapor space, ft.	20	25	25	15	25
ΔT	Avg. Daily temp. change, F	20	20	20	20	20
F_p	Paint factor	1.0	1.0	1.0	1.0	1.0
B	Breathing losses, lb/hr	18.4	9.2	6.9	1.6	27.8
m	m factor	3×10^{-4}	3.24×10^{-4}	2.76×10^{-4}	2.9×10^{-4}	$\sim 3.2 \times 10^{-4}$
N	Yearly turnovers	22.5	22.8	23.4	23.1	46.4
F_f	Working losses, lb/hr	52.1	28.1	17.8	2.9	299.3
	Total Losses, lb/hr	70.5	37.3	24.7	4.5	327.1
	M/W factor, gal/lb-mole	NA	NA	NA	NA	3.309
	Corrected Loss, lb/hr	70.5	37.3	24.7	4.5	86.6
	TOTAL Losses employing vapor recovery, lb/hr	3.53	1.86	1.23	0.22	4.16*

*lb/hr of NH_3 based on vapors being 96% NH_3

$$B = \frac{2.74 \times W \times K \times 42}{24 \times 1000} \left(\frac{P}{14.7-P}\right)^{0.68} D^{1.73} H^{0.51} \Delta T^{0.50} F_p$$

$$F_f = WmPT\left(\frac{180 + N}{6N}\right) \text{ where } T = \frac{\text{gals}}{\text{hr}} \text{ throughput}$$

NA= Not Applicable

Source: Radian Corporation. Characterization of Waste Effluents From A Lurgi Gasification Plant, Technical Note. Austin, Tex.: Radian Corp., 1975.

TABLE 3-83. BY-PRODUCT STORAGE EMISSION LOSSES - SYNTHANE

	Symbol	B-T-X[1]	Tar	Ammonia
W	Liquid density, lb/gal	6.41	8.91	7.48
K	K factor	0.024	0.019	~0.023
V	Tank Capacity, bbl.	13,000(2)	40,000(2)	56,000(1)
P	Vapor pressure, psia	5.8	~0.5	4.76
D	Tank diameter, ft.	48	76	90
H	Avg. Vapor space, ft.	20	25	25
ΔT	Avg. Daily temp. change, F	20	20	20
F_p	Paint factor	1.0	1.0	1.0
B	Breathing losses, lb/hr	18.4	6.9	27.8
m	m factor	3×10^{-6}	2.76×10^{-6}	$\sim 3.2 \times 10^{-6}$
N	Yearly turnovers	13.6	21.0	25.0
F_f	Working losses, lb/hr	44.7	15.8	104.3
	Total Losses, lb/hr	63.1	22.7	132.1
	M/W factor, gal/lb-mole	NA	NA	3.309
	Corrected Loss, lb/hr	63.1	22.7	35.0
	TOTAL Losses employing vapor recovery, lb/hr	3.2	1.1	1.7[2]

[1] Benzene, Toluene, Xylene

[2] lb/hr of NH based on vapors being 96% NH

$$B = \frac{2.74 \times W \times K \times 42}{24 \times 1000} \cdot \left(\frac{P}{14.7-P}\right)^{0.68} D^{1.73} H^{0.51} \Delta T^{0.50} F_p$$

$$F_f = WmPT \left(\frac{180 + N}{6N}\right) \text{ where } T = \frac{\text{gals}}{\text{hr}} \text{ throughput}$$

NA = Not Applicable

$$\text{Corrected Loss} = \text{Total Loss} \times 0.8 \times \frac{M}{W}$$

Source: Radian Corporation. Characterization of Waste Effluents From A Synthane Gasification Plant, Technical Note. Austin, Tex.: Radian Corp., 1976.

high pressure streams and halved if they handled water/hydrocarbon streams. Table 3-84 lists the adjusted pump seal emission factors, the estimated number of pumps for each type service and the pump seal emissions. All pumps are assumed to use mechanical seals. Table 3-85 lists the valve emission factors, the estimated number of valves and the valve emissions.

The composition of the fugitive emissions from valves and pump seals is a mixture of the various streams found in the gasification plants. No attempt is made to identify or quantify the compounds present in the fugitive emissions. However, in addition to the assumptions regarding number and types of valves and pumps and emission factors for estimating losses, it was also assumed that the emissions were primarily hydrocarbons. The actual fugitive hydrocarbon emissions, however, could vary substantially at an operating gasification facility. The values reported in Tables 3-83, 3-84, and 3-85 are intended only as an order of magnitude estimate.

Air emissions from facilities for the storage of NH_3 and the hydrocarbons (Table 3-83) are calculated by using storage capacity and emissions factors from the Compilation of Air Pollutant Emission Factors[1], assuming use of best available control techniques.

The ability of a gasification process to limit its air emissions to those given above will depend to a large extent on the prevention of fugitive emissions from pump seals, joints, flanges, etc. Proper maintenance should allow fugitive emissions to be controlled.

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[1] Environmental Protection Agency. Compilation of Air Pollutant Emission Factors, 2nd ed., with supplements. AP-42. Research Triangle Park, N.C., Feb. 1972, April 1973, July 1973, Sept. 1973, July 1974, Jan. 1975, Dec. 1975, Feb. 1976, April 1977.

TABLE 3-84. PUMP SEAL EMISSIONS

Type of Stream Handled by Pump	Number of Pumps	Emission Factor, lb/day	Air Emission lb/day
Water/Hydrocarbon Stream (low pressure)	18	0.25	4.5
Hydrocarbon Stream (low pressure) or Water/Hydrocarbon Stream (high pressure)	48	0.50	24.0
Gaseous Stream (high pressure)	12	1.0	12.0
TOTAL			40.5

TABLE 3-85. FUGITIVE EMISSIONS FROM VALVES

Type of Service in Which Valve is Used	Number of Valves	Emission Factor, lb/day	Air Emission, lb/day
Gaseous	930	0.486	757
Liquid	1360	0.108	147
TOTAL			904

Trace Organics

One of the concerns and potential dangers of coal gasification plants is the trace organics and inorganics that may be emitted. Literature data concerning the formation and fate of trace organics and inorganics in coal gasification processes are very limited. However, limited analogies can be drawn between the gasification process and the conventional coking and coal combustion processes to give insight into the identification, quantification, and ultimate face of trace compounds produced in the gasification process.

There are two major sources of the organic materials from coal processing: those originally present in the coal which are released through volatilization and those formed by chemical reaction in the gasifier and associated equipment. A considerable body of information exists concerning the identity of individual components in coals, and a significant amount of work has been done toward defining the products from coal pyrolysis or thermolysis. However, each coal has a unique composition. As a result the available data cannot be generalized and applied for all cases, but must be evaluated in terms of the coal composition and the process (reaction and operating conditions) involved.

Although the molecular composition cannot be specified precisely, a number of functional groups are found in coal, and a similar functional group pattern is probably followed in the plant effluents. In all processes which gasify coal at intermediate temperatures, the gasifier output may contain all of the products commonly associated with pyrolysis, carbonization, and coking of coals in addition to oxygenated products associated with partial combustion. As it is unlikely that gasification conditions will result in complete conversion of all components, the possibility exists that traces of any of the organic compounds (functional groups) will be found in the plant effluent streams.[1]

Due to the lack of directly applicable information concerning detailed compositions of streams from a gasification plant, data on emissions from processes such as boilers and coke ovens, which have been characterized in more detail, must be examined.

Battelle[2] reported forty-two toxic and hazardous organic substances likely to be emitted by industrial boilers (see Table 3-86). The organic compounds are listed in order of their decreasing health hazard. Although the first twelve compounds are all potent carcinogens, this rating is intended only as a guide since a direct comparison of the potency of the various hazardous materials is not always possible.

In a coke plant, cyclic and polycyclic organic matter present in coke oven emissions will be found primarily in the particulate fraction which has been defined as tar. The principal compounds obtained from coal tar as presented by Roberts[3] and Morrison[4] are given in Tables 3-87 and 3-88, respectively. Several of the more widely accepted carcinogens are species of benzpyrene. To characterize the presence of this general group, benzpyrene analyses were performed on the coal tar from a number of coke over samples.[5]

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[1] Radian Corporation. Technical and Cost Proposal for the Selection and Development of Procedures to Assure the Environmental Acceptability of Coal Utilizing Processes. Austin, Tx.: Radian, 1973.

[2] Barrett, R. E., et al. Assessment of Industrial Boiler Toxic and Hazardous Emissions Control Needs, Final Report. Columbus, Ohio: Battelle Columbus Laboratories, 1974.

[3] Radian Corporation, *op.cit.*

[4] Morrison, Robert Thornton, and Robert N. Boyd. Organic Chemistry, 2nd ed. Boston, Mass.: Allyn & Bacon, 1966.

[5] Bee, R. W., et al. Coke Oven Charging Emission Control Test Program, Final Report. McLean, Va.: Mitre Corp., 1974, Vol. I

TABLE 3-86. TOXIC AND HAZARDOUS SUBSTANCES LIKELY TO BE EMITTED BY INDUSTRIAL BOILERS

Organic Materials

7,12-Dimethyl Benz(a)anthracene
3-methylcholanthrene
Dibenz(a,h)anthracene
Benz(c)phenanthrene

Benz(a)pyrene
Dibenz(a,h)pyrene
Dibenz(a,i)pyrene
Dibenz(c,g)carbazole

4-Aminobiphenyl
Benzidine
1-Naphthylamine
4-Nitrobiphenyl
Phenylhydrazine

Methyl-phenylhydrazine
Dibenz(a,j)acridine
Dibenz(a,h)acridine
Cholanthrene

Benz(j)fluoranthene
Benz(b)fluoranthene
Dibenz(a)anthracene
Dibenz(a,c)anthracene

Dibenz(a,j)anthracene
Dibenz(a,g)fluorene
Indeno(1,2,3-cd)pyrene
Dibenzo(a,l)pyrene

Benz(a)anthracene
Chrysene
Dibenz(a,c)fluorene
Dibenz(a,h)fluorene

Dibenz(a,i)carbazole
Benz(a)carbazole
Dibenz(c,h)acridine
Picene
Dibenz(a,g)carbazole

Benzoquinoldine
Piridine
Acridine
Aniline

Phenol
Benzthiophenes
Dibenzthiophenes
Thiophene

Source: Barrett, R. E., et al. Assessment of Industrial Boiler Toxic and Hazardous Emissions Control Needs, Final Report. Columbus, Ohio: Battelle Columbus Laboratories, 1974.

TABLE 3-87. PRINCIPAL COMPOUNDS OBTAINED FROM COAL TAR

Hydrocarbons	Nitrogen Compounds	Oxygen Compounds
Naphthalenes	Pyridines	Phenols
Acenapthene	Quinoline	Cresols
Fluorene	Carbazole	Xylenol
Anthracene	Acridine	Naphthols
Phenanthrene	Picoline	
Chrysene		
Pyrene		
Fluoranthene		

Source: Roberts, John D. and Marjorie C. Caserio. Basic Principles of Organic Chemistry. N.Y.: W. A. Benjamin, 1965.

TABLE 3-88. COMPOUNDS OBTAINED FROM COAL TAR

Benzene
Toluene
Xylenes
Phenols
Cresols
Naphthalenes
Anthracene

Phenanthrene
Thiophrene
Thiophene
Pynole
Pyridine
Quinoline

Source: Morrison, Robert Thornton, and Robert N. Boyd. Organic Chemistry, 2nd ed. Boston, Mass.: Allyn & Bacon, 1966.

Results indicated benzpyrene is present in concentrations ranging from less than 260 ppm to 18,000 ppm. The combination of mass spectra and chromatographic data resulting from the above samples clearly indicated the presence of benz(c)-phenanthrene (potent carcinogen), benz(a)anthracene (carcinogen), a benzfluoranthene isomer (possible carcinogen), benz(a)pyrene (potent carcinogen) and/or benz(e)pyrene, and cholanthrene (carcinogen).

In a study of the effluents from an experimental coal gasification plant, certain organic components were extracted and tentatively identified (Table 3-89). The particular distribution of organic compounds present in raw gasifier gas will depend on the composition of the feed coal and on the operating conditions of the gasifier. The range of sulfur and benzene-toluene-xylene components which might be expected from the Synthane Process are given in Table 3-90 for six coal feeds.

It should be noted that conclusions as to the ultimate fate of trace organics in a coal gasification plant depend primarily upon emissions of particulate tars which high efficiency collection equipment could control. This discussion, therefore, is intended to present only the "potential" dangers.

Trace Inorganics

Elements present in concentrations of 0.1 percent (1,000 ppm) or less are usually referred to as trace elements. The main source of the trace elements found in coal is the mineral matter associated with living plant tissues. Table 3-91 lists the trace element analysis of a typical coal feedstock.

The potential hazards of trace elements present a definite incentive for determining the ultimate fate of these various species in coal conversion systems. Unfortunately, very little

TABLE 3-89. COMPOUNDS TENTATIVELY IDENTIFIED IN WASTE EFFLUENTS OF COAL GASIFICATION PILOT PLANT

Restructured Gas Chromatograph Peak	Best Match	Second Best Match
1	Phenol	Phenol
2	o-Cresol	m-Cresol
3	m-Cresol	o-Cresol
4	2,5-Dimethylphenol	2,6-Dimethylphenol
5	3,4-Dimethylphenol	3,4-Dimethylphenol
6	2,4-Dimethylphenol	3,4-Dimethylphenol
7	a-Naphthol	1,2-Dihydroxynaphthalene

Source: McGuire, J. M., A. L. Alford, and M. H. Carter. Organic Pollutant Identification Utilizing Mass Spectrometry. Athens, Ga.: Environmental Protection Agency, Southeast Environmental Research Laboratories, 1973.

TABLE 3-90. COMPONENTS IN SYNTHANE GASIFIER GAS, ppm

	Illinois No. 6 Coal	Illinois Char	Wyoming Subbi-tuminous Coal	Western Kentucky Coal	North Dakota Lignite	Pitts-burgh Seam Coal
H_2S	9,800	186	2,480	2,530	1,750	860
COS	151	2	32	119	65	11
Thiophene	31	.4	10	5	13	42
Methyl thiophene	10	.4	--	--	--	7
Dimethyl thiophene	10	.5	--	--	11	6
Benzene	340	10	434	100	1,727	1,050
Toluene	94	3	59	22	167	185
C_8 aromatics	24	2	27	4	73	27
SO_2	10	1	6	2	10	10
CS_2	10	--	--	--	--	--
Methyl mercaptan	60	.1	.4	33	10	8

Source: Forney, Albert J., et al. Analyses of Tars, Chars, Gases, and Water Found in Effluents From the Synthane Process, Bureau of Mines Technical Progress Report 76. Pittsburgh, Pa.: Pittsburgh Energy Research Center, 1974.

Kalfadelis, C. D. and E. M. Magee. Evaluation of Pollution Control in Fossil Fuel Conversion Processes; Gasification. Section I: Synthane Process, Final report. Linden, N.J.: Esso Research & Engineering Co., 1974.

TABLE 3-91. TRACE ELEMENT ANALYSIS OF A TYPICAL COAL FEEDSTOCK

Element	ppm by Weight
Antimony	0.3 - 1.2
Arsenic	0.1 - 3.0
Bismuth	0.0 - 0.2
Boron	60.0 - 150.0
Bromine	0.4 - 18.0
Cadmium	0.2 - 0.4
Fluorine	200.0 - 780.0
Gallium	0.5 - 8.0
Germanium	0.1 - 0.5
Lead	1.4 - 4.0
Mercury	0.2 - 0.3
Nickel	3.0 - 30.0
Selenium	0.1 - 0.2
Zinc	1.1 - 27.0

Source: U.S., Dept. of the Interior, Bureau of Reclamation. El Paso Gasification Project, N.M.: Draft Environmental Statement. Salt Lake City: Bureau of Reclamation, Upper Colorado Region, 1974.

data on the fate of trace elements in coal processing facilities have been published. Attari[1] has reported some data in connection with the IGT HYGAS pilot plant. The purpose of this work was to measure the concentrations of 11 trace elements found in the solid streams entering and leaving the various stages of the HYGAS pilot plant.

Because the pilot plant was not operational during the period when the analytical work was performed, coal and char samples accumulated over several years of bench-scale research were used in the analysis. The emphasis of the project was placed on trace element analytical methods since sampling and operating criteria of the pilot plant were not involved. The relative amounts of the trace elements found in the overhead gas and the spent char from the electrothermal gasifier are presented in Table 3-92. The amount of each element assumed to be in the overhead gas was calculated by difference. It can be seen from these data that most of the Hg, Se, As, Te, Pb and Cd which entered the gasifier in the coal feed apparently left the gasifier in the vapor phase. Most of the Sb, V, Ni, Be and Cr remained in the solid phase.

In addition to this data, analogies may be drawn between a coal gasification plant and a coal-fired power plant since the same trace elements are present in the coal and the coal will pass through an oxidizing atmosphere similar to that present in a boiler. One such analogy can be drawn from the results of a material balance for 17 trace elements carried out on a pulverized-coal-fired power plant.[2] In this study it was found that

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[1] Attari, A. Fate of Trace Constituents of Coal During Gasification, Final Report. Chicago: Institute of Gas Technology, 1973.

[2] Kaakinen, John W., Roger M. Jorden, and Ronald E. West. "Trace Element Study in a Pulverized-Coal Fired Power Plant." Denver: June 1974.

TABLE 3-92. TRACE ELEMENT CONCENTRATION OF COAL CALCULATED ON RAW COAL BASIS

Trace Element	Gas* Overhead (%)	Spent Char Bottom (%)
Hg	96	4
Se	74	26
As	65	35
Te	64	36
Pb	63	37
Cd	62	38
Sb	33	67
V	30	70
Ni	24	76
Be	18	82
Cr	0	100

* The % of the trace element in the overhead gas was calculated by difference as only solid analysis was done.

Source: Attari, A. Fate of Trace Constituents of Coal During Gasification, Final report. Chicago: Institute of Gas Technology, 1973.

alumium, iron, rubidium, strontium, yttrium, and niobium concentrations are essentially constant in all outlet ash streams (fly ash and bottom ash). Copper, zinc, arsenic, molybdenum, antimony, lead, and the radioisotopes lead-210 and polonium-210 were found in progressively higher concentrations in fly ash fractions collected downstream of the firebox. These trace elements were in their lowest concentrations in the bottom ash. The bulk of the trace elements found in both of these groups were retained in the solid phase.

The inability to close the mass balances for mercury and selenium based only on solid and liquid samples suggested that portions of these two elements existed as vapors and/or very fine aerosols in flue gas which passed through the sampling equipment. Also, the enrichment of certain trace elements in successive fly ash fractions collected in the downstream direction is probably due to volatilization of these elements or their compounds in the furnace and their subsequent condensation or adsorption onto suspended fly ash particles. Natush, Wallace, and Evans[1] likewise reported that the trace elements arsenic, antimony, cadmium, lead, selenium, and thallium probably volatilize in the furnace and recondense on small ash particles as the flue gas cools. Due to the similarity between a coal gasification reactor and a power plant boiler, this data suggests one possible fate of trace elements in a gasification system. This analogy is limited, however, in that coal fed into a power plant boiler encounters only an oxidizing atmosphere and the coal combustion products are either gaseous or solid. In a gasifier, however, part of the coal is vaporized and leaves the system while the char which remains enters the combustion zone at the bottom of the gasifier. In this oxidizing atmosphere, the char is combusted with oxygen in the presence of steam to produce a gas mixture containing hydrogen which is fed to the top section of the gasifier. Because trace elements in a Lurgi gasifier first encounter a reducing atmosphere, then an oxidizing atmosphere with possible recycle through the reducing atmosphere, it is difficult to predict the possible distributions of specific trace elements among the gasifier effluent streams.

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[1] Natusch, D. F. S., J. R. Wallace, and C. A. Evans, Jr. "Toxic Trace Elements: Preferential Concentration in Respirable Particles." Science 183 (January 18, 1974): 202-204.

Based on the recent studies of trace elements in a coal-fired power plant[1] and in a coal gasification system[2], only limited conclusions can be made as to the ultimate fate of trace elements in a gasification plant. The HYGAS data cannot necessarily be related to the Lurgi or Synthane gasification system. Furthermore, the samples analyzed (solids only) were from bench-scale work, and therefore may not be representative of commercial scale operation. Nevertheless, it is obvious from these studies that certain trace elements have a tendency to volatilize while others tend to remain in the ash or char. Data on the volatility of trace elements in coal as reported by Ruch, Gluskoter, and Shimp[3] are given in Table 3-93.

There seems to be some agreement that portions of the Hg and Se exist as vapors and/or fine aerosols in the gas stream. The gasification data indicate that As, Te, Pb, and Cd volatilize to some degree and that a portion of the trace elements would leave the gasifier in the overhead gas stream. Also, the power

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[1] Kaakinen, John W., Roger M. Jorden, and Ronald E. West. "Trace Element Study in a Pulverized-Coal Fired Power Plant." Denver: June 1974.

[2] Attari, A. Fate of Trace Constituents of Coal During Gasification, Final Report. Chicago: Institute of Gas Technology, 1973.

[3] Ruch, R. R., H. J. Gluskoter, and N. F. Shimp. Occurrence and Distribution of Potentially Volatile Trace Elements in Coal. Urbana, Ill.: Illinois State Geological Survey, 1974.

TABLE 3-93. VOLATILITY OF TRACE ELEMENTS IN COAL

Low-Temperature Ash			High-Temperature Ash		
Retained (>95%)		Lost	Retained*		Lost
Ga	Cu	Hg (up to 90%)	Zn	Cd	Mo (33%)
Se	Pb	Br (100%)	Ni	Mn	V (possibly up to 25%)
As	V	Sb (up to 50%)	Co	Cr	
Zn	Mn	F (untested but presumed lost)	Cu	Be	
Ni	Cr		Pb	Ge	
Co	Cd		B	Sn	
Be				Se (untested but presumed retained)	

* No significant losses observed in coal ash from 300° to 700°C or between results from whole coal and low-temperature ash or high-temperature ash (~450°C).

Source: Ruch, R. R., H. J. Gluskoter, and N. F. Shimp. Occurrence and Distribution of Potentially Volatile Trace Elements in Coal. Urbana, Il.: Illinois State Geological Survey, 1974.

plant study concluded that Cu, Zn, As, Pb, Mo, and Sb were at least partially volatilized in the furnace and then condensed or adsorbed onto suspended fly ash particles.

These data clearly indicate the loss of certain trace elements during gasification. However, no conclusion as to the final disposition of all of the trace elements leaving the gasifier was possible. In addition, the chemical forms in which the trace elements occurred were not examined in any of the streams.

As can be seen from the previous discussion, the primary sources of air emissions from the gasification facilities are combustion and process losses. Tables 3-94 and 3-95 summarize the sources of air contaminants from a Lurgi and Synthane facility, respectively. Tables 3-96 and 3-97 summarize emission rates of the five criteria pollutants along with stack data. In all cases where a stack was present, a height of 300 ft. and a stack gas velocity of 60 Fps were assumed.

3.8.1.3b Water Effluents

Data developed by El Paso Natural Gas Company for a proposed coal gasification plant utilizing a Lurgi gasifier to produce 275 x 10^9 Btu/day of SNG indicate that 620,000 lb/hr or 1240 gpm of wastewater would be produced.[1] Assuming that the quantity of wastewater produced is proportional to plant throughput, approximately 565,000 lb/hr (1130 gpm) of liquid waste would be produced by a 250 x 10^6 scf/day Lurgi gasification facility. These wastes contain high levels of dissolved solids, hazardous organic and trace inorganic compounds, and possibly carcinogenic organic species.

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[1] El Paso Natural Gas Co. Application of El Paso Natural Gas Co. for a Certificate of Public Convenience and Necessity. El Paso, Tex.: El Paso Natural Gas Co., 1973.

TABLE 3-94. SUMMARY OF GASEOUS EFFLUENT STREAMS - LURGI COAL GASIFICATION

Waste Stream	Temperature °F	Pressure psig	Contaminants
Boilers and Turbines Stack Gas	300°F	0	Particulates NO_x SO_2
Steam Super Heater Stack Gas	300°F	0	Particulates NO_x SO_2
Fuel Gas Heater Stack Gas	300°F	0	Particulates NO_x SO_2
Incinerator Stack Gas	300°F	0	Particulates NO_x SO_2
Oxygen Production Vent Gases	Ambient	0	None
Water Treating Degasser Vent	Ambient	0	None
Steam and Power Production Deaerator Vents	200°F	0	Negligible
Cooling Tower Evaporation	Ambient	0	H_2S NH_3
Cooling Tower Drift	Ambient	0	Dissolved Solids Trace Elements Trace Organics
Pond Evaporation	Ambient	0	Negligible
Fugitive	--	-	H_2S NH_3 CO HC Trace Elements Trace Organics

Source: Radian Corporation. Characterization of Waste Effluents From a Lurgi Gasification Plant, Technical Note. Austin, Texas: Radian Corporation, 1975.

TABLE 3-95. SUMMARY OF GASEOUS WASTE EFFLUENTS - SYNTHANE COAL GASIFICATION

Waste Stream	Temperature °F	Pressure psig	Contaminants
Combustion Stack Gases	200	0	Particulates Hydrocarbons CO SO_2 NO_x Trace Elements Trace Organics
Sulfur Recovery Vent Gases	150	0	H_2S CO
Oxygen Production Vent Gases	75	0	
Cooling Tower Evaporation	Ambient	0	H_2S NH_3 Trace Organics Trace Elements
Cooling Tower Drift	Ambient	0	H_2S NH_3 Trace Organics Trace Elements
Fugitive Emissions			H_2S NH_3 CO Hydrocarbons Trace Elements Trace Organics

Source: Radian Corporation. Characterization of Waste Effluents From a Synthane Gasification Plant, Technical Note. Austin, Texas: Radian Corporation, 1975.

TABLE 3-96. AIR EMISSIONS OF CRITERIA POLLUTANTS FROM A 250 MMscfd LURGI PLANT

Source	Air Emissions (lb/hr)					Stack Parameters				
	Particulate	SO_2	NO_x	CO	HC	Stream Rate(lb/hr)	Volumetric Flow(ACFM)	Velocity (fps)	Height (ft)	Temp. (°F)
Boilers and Turbines	negligible	248	418	--	--	5.7×10^6	1.8×10^6	60	300	300
Steam Superheater	negligible	34	57	--	--	0.31×10^6	0.10×10^6	60	300	300
Fuel Gas Heater	negligible	8	13	--	--	68×10^3	22×10^3	60	300	300
Incinerator	negligible	226	161	--	--	1.6×10^6	0.5×10^6	60	300	300
Storage	--	--	--	--	7	7	--	--	50	--
Fugitive Losses	--	--	--	--	40	40	--	--		
TOTAL	negligible	516	649	--	47					

Source: Radian Corporation. Characterization of Waste Effluents From a Lurgi Gasification Plant, Technical Note. Austin, Texas: Radian Corporation, 1975.

TABLE 3-97. AIR EMISSIONS OF CRITERIA POLLUTANTS FROM A 250 MMscfd SYNTHANE PLANT

Source	Air Emissions (lb/hr)					Stack Parameters				
	Particulate	SO_2	NO_x	CO	HC	Stream Rate(lb/hr)	Volumetric Flow(ACFM)	Velocity (fps)	Height (ft)	Temp. (°F)
Combustion Gases	8	3524	5052	168	50	3.0 x 10	0.85 x 10	60	300	200
Sulfur Recovery	--	--	--	8	--	2.4 x 10	0.61 x 10	60	300	150
Storage	--	--	--	--	4	4	--	--	50	--
Fugitive Losses	--	--	--	--	40	40	--	--		
TOTAL	8	3524	5052	176	94					

Source: Radian Corporation. Characterization of Waste Effluents From a Synthane Gasification Plant, Technical Note. Austin, Texas: Radian Corporation, 1975.

Because of the presence of these hazardous compounds in a gasification plant's liquid wastes, the facility considered here is assumed to operate in a "zero liquid discharge" manner. All potential liquid effluents are either treated for reuse within the process or sent to evaporation ponds for disposal. Thus, no liquid effluents are discharged from the boundary limits of the conversion facility.

The following sections characterize the expected contaminants contained in these internal liquid streams. The values reported herein are for the 288 MMscfd Lurgi gasification facility as proposed by El Paso Natural Gas. The actual quantities for the 250 MMscf facility analyzed here are expected to be somewhat less but the effluent components should be the same. In addition, the liquid waste streams within the Synthane facility will be similar. It should be remembered, however, that the facilities are designed to produce no liquid discharges and the following description is of internal waste streams. Table 3-98 shows the analysis of the raw water used as a make-up to these processes.

Potential liquid effluents within the conversion processes include:

- the oily and tarry gas liquors,
- boiler blowdowns,
- process condensates,
- cooling tower blowdown,
- demineralizer and zeolite softener regenerations wastes,
- lime softener sludge,

TABLE 3-98. RAW WATER ANALYSIS

Compounds	mg/1
Carbonate Hardness as $CaCO_3$	211.0
Non-Carbonate Hardness as $CaCO_3$	93.0
Ca^{++}	66.0
Mg^{++}	9.1
Na^{+}	45.0
HCO_3^{-}	144.0
$CO_3^{=}$	0.0
$SO_4^{=}$	168.0
Cl^{-}	14.0
SiO	11.0
pH^2 (pH units)	7.8

Source: U.S. Dept. of the Interior, Bureau of Reclamation, Upper Colorado Region. El Paso Gasification Project, San Juan County, N.M., draft environmental statement. DES-74-77. 1974.

- sewage treatment wastes, and
- ash quenching overflow.

Tarry and oily gas liquors are produced by cooling raw synthesis gas and condensing a portion of the stream's water content. Both the air and oxygen blown Lurgi gasifiers produce tarry and oily gas liquors. During the cooling process, soluble gases present in the synthesis gas, such as CO_2, CO, H_2S and NH_3, dissolve in the condensate stream. Moreover, heavy hydrocarbons, phenols and trace inorganic compounds present in the synthesis gas also condense or dissolve in the water stream.

To permit reuse of the water content of the gas liquors and to recover valuable by-products, the Lurgi process employs three phases of gas liquor treatment. Separate but analogous treatment trains are employed for the tarry and oily gas liquors. The first treatment step employs physical separation vessels for the recovery of the tars and tar oils present in the gas liquor. The second treatment step entails extraction with isopropyl ether of the phenolic compounds. Finally, ammonia and acid gases are stripped from the gas liquors by steam reboilers.

However, even after treatment, the oily and tarry gas liquors probably contain small or trace amounts of heavy hydrocarbons, trace inorganics and dissolved gases. Thus, these streams still represent potential liquid pollutants and must be reused within the process or disposed of in the solar evaporation ponds. In the design, 164,000 lb/hr of treated tarry gas liquor is sent to the ash quenching area, about 1,070,000 lb/hr of treated oily gas liquor is used as cooling water makeup, and the remaining 122,000 lb/hr is sent to the evaporation ponds.

Another source of internal wastewater is the boiler blowdown. This blowdown is required to prevent scaling of the boiler tubes. These streams contain increased levels of dissolved compounds such as Ca^{++}, Na^{+}, Mg^{++}, $SO_4^{=}$, NO_3^{-}, Cl^{-}, and $CO_3^{=}$. To insure the clean operation of the process boilers, the concentration of these ions in the boiler waters is kept well below their saturation levels. Therefore, it is possible to reuse the blowdown streams elsewhere in the process where higher levels of dissolved solids can be tolerated.

Boiler blowdown produced from the high and medium pressure boilers still has enough heat content to produce low pressure steam upon flashing. The liquid remaining after flashing is combined with the blowdown from the low pressure boilers and used as cooling system make-up water. Approximately 228,000 lb/hr of boiler blowdown is sent to the cooling system. Thus, the boiler blowdown streams are completely reused within the process and do not represent liquid effluents.

Besides the tarry and oily gas liquors produced from the gasification and cooling areas, process condensates are produced from the gas purification, methanation, dehydration and compression areas. These condensates are essentially pure water and are recycled within the process. The gas purification condensate (103,000 lb/hr) is reused within the gas liquors. The condensate from the methanation area (315,000 lb/hr) is degassed and combined with the softened water produced in the water treating area. The condensates produced from the dehydration and compression area are sent to the cooling system as make-up water (715 lb/hr) and to the ash quenching area (535 lb/hr).

A fourth source of liquid wastes is the cooling tower blowdown. The cooling water system dissipates heat via evaporation of a portion of the recirculating cooling water. To prevent scaling in the heat exchangers and condensers of the system, approximately 224,000 lb/hr of the recirculating water is removed as blowdown. This stream contains high levels of dissolved solids and any other contaminants, *i.e.*, trace organics and inorganics, present in the cooling system water. Table 3-99 is an analysis of a typical cooling tower blowdown stream. The cooling tower blowdown is reused in the ash quenching area and hence does not represent a liquid effluent.

TABLE 3-99. TYPICAL COOLING TOWER BLOWDOWN WATER ANALYSIS

Compounds	mg/l
Ca^{++}	793
Mg^{++}	156
Na^{+}	975
Cl^{-}	1,567
$CO_2(\ell)$	7
NO_3^{-}	8
$SO_4^{=}$	2,416
pH (pH units)	7.5

A lime softener/clarifier is utilized as the primary water treatment step in the Lurgi process. This unit reduces the Ca^{++} concentration of the raw water feed by the mechanism shown in Equation 5.5-1.

$$Ca(OH)_2 + 2HCO_3^{-} + Ca^{++} \rightarrow 2CaCO_3\downarrow + 2H_2O \quad (5.5\text{-}1)$$

The precipitated $CaCO_3$ and any unreacted $Ca(OH)_2$, are removed from the clarifier in a slurry form. This slurry is sent to the ash quenching area where it is combined and disposed of with the quenched ash.

Ion exchange demineralizers and sodium zeolite softeners are used in the water treatment area to condition the lime treated water prior to its use as boiler feed water. Regeneration of these units produces liquid streams concentrated in dissolved species consisting mainly of Na^+, Ca^{++}, Mg^{++}, Cl^-, $SO_4^=$, NO_3^- and $CO_3^=$. However, these streams (134,000 lb/hr) are not discharged from the Lurgi facility but are sent to the ash quenching area for further use.

Potable water is produced on-site for in-plant users. The resultant wastewater (10,000 lb/hr) is treated and directed to the cooling system for use as makeup. The plant utility water system produces 50,000 lb/hr of contaminated water which is treated in API separators before being sent to the ash quenching area.

The ash quenching area receives wastewaters from many sources within the Lurgi process, including:

- cooling tower blowdowns,
- treated gas liquor,
- demineralizer and sodium zeolite softener regenerator wastes,
- plant utility water system wastes, and
- dehydration and compression condensate.

These waste streams, approximately 592,000 lb/hr, are used to quench the warm gasifier ash. In addition, 108,000 lb/hr of water associated with the lime treater sludge is combined with the quenched ash. The ash and sludge are separated in a clarifier with the resultant overflow (530,000 lb/hr) being sent to the solar evaporation ponds for final disposal. This stream will contain any of the contaminants present in the quench water as well as mineral matter (see Table 3-100) leached from the coal ash. The exact concentration of the contaminants in this stream cannot be quantitatively determined, but discharge of this stream would most likely violate existing water quality standards.

TABLE 3-100. MINERAL CONSTITUENTS OF COAL ASH

1.	Al_2O_3
2.	CaO
3.	Fe_2O_3
4.	K_2O
5.	MgO
6.	Na_2O
7.	P_2O_5
8.	SiO_2
9.	SO_3
10.	TiO_2
11.	FeO

Source: O'Gorman, J. V. and P. L. Walker, Jr. Mineral Matter and Trace Elements in U.S. Coals. Pennsylvania State University, Coal Research Station, 1972.

As was discussed previously with regard to air emissions, there exists a potential for the production of many different types of trace organics and trace inorganics at a gasification facility. These compounds will most likely be found in most of the internal wastewater streams discussed above. These potential contaminants are the same compounds as those listed in Section

3.8.1.3a. As with the air emissions, however, the exact concentration and composition of these compounds in the waste streams is unknown.

A summary of the contaminants contained in these internal liquid waste streams is shown in Table 3-101.

3.8.1.3c Solid Wastes

Solid wastes from the coal gasification plants consist of 1) ash, 2) lime softener sludge, 3) spent shift catalyst, and 4) spent methanation catalyst. In addition the Synthane facility produces limestone wet scrubber sludge from the SO_2 control equipment on the utility boiler.

The ash from the Lurgi facility is from the air and oxygen blown gasifiers. The Colstrip, Montana, coal fed to these gasifiers contains about 10% ash. Based on a coal feed rate of 20,190 TPD to the SNG production gasifiers and 4330 TPD to the fuel gas producing gasifiers, approximately 204,000 lb/hr of ash is produced. In addition, approximately 20,700 lb/hr of unburned coal is retained with the ash. Therefore, a total of 225,000 lb/hr of solid wastes is sent to the ash quenching area. Water is used to cool this ash and it is then returned to the coal mine for disposal. Approximately 82,000 lb/hr of water remains with the ash.

To provide enough energy for the Synthane facility to be self-sufficient with respect to steam and power needs a char-fired utility boiler is included. Assuming that all the ash in the coal leaves the gasifier in the char, approximately 180,000 lb/hr of ash is produced by the 21,530 TPD of Colstrip, Montana, coal fed to the gasifiers. It is further assumed that virtually all the residual coal in the char is combusted in

TABLE 3-101. SUMMARY OF LIQUID PHASE EFFLUENT STREAMS

Waste Streams	Contaminants
Gas Liquors Before Treatment	H_2S NH_3 Tars Tar Oil Phenols CO CH_4 Trace Organics Trace Elements
Gas Liquors After Treatment	Trace Elements Trace Organics H_2S NH_3
Boiler Blowdown	Dissolved Solids
Process Condensates	Negligible
Cooling Tower Blowdown	Trace Elements Trace Organics Dissolved Solids
Ash Quench Water	Trace Elements Trace Organics Dissolved Solids Mineral Matter

the utility boiler. This ash is removed as bottom ash and electrostatic precipitator fly ash. The major constituents of this ash are oxides of calcium, iron, aluminum, potassium, titanium, magnesium, sodium and silicon. Other components of the ash include trace elements and trace organics.

In addition, this utility boiler utilizes limestone wet scrubbing. The removal of SO_2 from flue gas by limestone wet scrubbing produces a sludge containing $CaSO_3 \cdot \frac{1}{2}H_2O$, $CaSO_4 \cdot 2H_2O$, $CaCO_3$, fly ash, and water. The sludge is assumed to be filtered and settled until a 50 wt. % solids is attained. An analysis of the limestone scrubber sludge is given in Table 3-102. The scrubber is designed to reduce the SO_2 concentration of the resulting stack gas to the national new source standard of 1.2 lb SO_2/MM Btu and remove 99% of the inlet fly ash. This solid waste effluent is at ambient temperature and pressures.

TABLE 3-102. COMPOSITION OF LIMESTONE SCRUBBER SLUDGE

	lb/hr	wt%
$CaSO_3 \cdot \frac{1}{2}H_2O$	34,100	31
$CaSO_4 \cdot 2H_2O$	16,300	15
$CaCO_3$	3,600	3
Ash	780	1
H_2O	54,800	50
	109,580	100

Another potential source of solid wastes is the lime-soda water softener. Based on the raw water analysis given in Table 4-9 and the ability to reduce the Ca^{++} concentration to 30 ppm by lime treating, 500 lb/hr of $CaCO_3$ are produced in the lime softener. This solid waste will also contain a small amount of suspended solids removed from the raw water and any excess lime used in the treater. At the Lurgi facility these solids are transported in slurry form to the ash quenching area where they are combined and disposed of with the gasifier ash. In the Synthane facility, however, this potential effluent is directed to the limestone wet scrubber as a partial source of makeup alkalinity. If this is not possible or if a different type scrubber is employed for flue gas cleanup, the softener sludge becomes a waste effluent.

The final major source of solid wastes at the gasification facilities is spent catalysts. In these processes, the shift and methanation reactors employ catalysts to achieve rapid chemical reaction. Periodically it is necessary to put new catalyst into service and dispose of the spent catalyst. However, the frequency of these replacements and the quantities of spent catalyst involved depend on several factors including operating conditions, type of catalyst, number of system upsets, etc. Therefore, the quantity of solid wastes resulting from catalyst replacement cannot be ascertained at this time, but provisions should be made for catalyst disposal.

As was discussed previously, virtually all of the solid wastes generated by these facilities will be handled on-site either by settling ponds or coal mine disposal. A summary of the contaminants contained in these wastes from a Lurgi and Synthane facility are shown in Tables 3-103 and 3-104.

3.8.1.3d Noise Pollution

The gasification facilities considered here will probably be located in remote areas and on sufficient land to minimize any noise problems at the property line. In one case, however, noise has been found to be excessive at a SNG plant.[1] Noise

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[1] Shaw, H. and E. M. Magee, Evaluation of Pollution Control in Fossil Fuel Conversion Processes; Gasification. Section I: Lurgi Process, Final report. EPA 650/2-74-009c. Linden, N.J.: Exxon Research & Engineering Co., 1974.

TABLE 3-103. SUMMARY OF SOLID PHASE EFFLUENTS - LURGI

Waste Stream	Temperature °F	Pressure psig	Contaminants
Wet Gasifier Ash	Ambient	0	Minerals Dissolved Solids Trace Elements Trace Organics
Lime Softener Sludge	Ambient	0	$CaCO_3$ $Ca(OH)_2$
Spent Catalyst	Ambient	0	Cobalt Molybdenum Vanadium Nickel

TABLE 3-104. SUMMARY OF SOLID WASTE STREAMS - SYNTHANE

Waste Stream	Temperature °F	Pressure psig	Contaminants
Utility Boiler Ash	350	15	Trace Elements Trace Organics Mineral Matter
Limestone Wet Scrubber Sludge	Ambient	15	Trace Element
Spent Catalysts	Ambient	15	

control mechanisms which can be utilized if necessary are as follows: any gas fired turbines should be enclosed and air and exhaust systems adequately muffled; sound reducing insulation should be placed on piping where needed; sound reducing panels and walls should be used in buildings where coal crushing and screening occurs; incinerators and boilers should be designed to minimize combustion noise. By utilizing these measures, where necessary, the noise problem will be minimal.

3.8.1.3e Occupational Health and Safety

The possible adverse health effects of the gasification facilities are primarily caused by the presence of toxic compounds. As was discussed in Sections 3.8.1.3a and 3.3.1.3b there are many toxic and/or potentially carcenogenic compounds present in the various streams. These compounds are primarily found in the waste streams and originate from the organics contained in the coal. As was discussed previously, however, the exact composition of these streams and concentration of these compounds is presently unknown. It is assumed that any adverse health effects caused by the presence of these compounds will be minimized by proper maintenance and minimized contact with oily wastes and other effluents. In addition, since the plants are operated on a zero liquid discharge manner, solid wastes are disposed of at the mine and stack gases are subjected to cleaning, the adverse health effects to surrounding areas will be minimized.

Another potential source of toxic compounds at the facilities are the toxic inorganic gases present. These compounds include the H_2S from the acid-gas removal and sulfur recovery processes and the ammonia from the gas liquor treating processes. Although these compounds are highly toxic it is assumed that adequate precautions are incorporated into the facility design to minimize the potential exposure of personnel to toxic levels.

The other potential health and safety problems which exist at the coal gasification facilities are those which exist at virtually every chemical processing facility. These include the potential for burns resulting from occurances such as contact with hot processing equipment, steam or combustion gases and the potential for accidents such as falls, etc.

Data on injuries, deaths, and man-days lost at these facilities are available from Battelle.[1] Converting from Battelle's basis of 10^6 Btu to a 250 MMscfd plant yields the following expected annual values: 0.45 deaths, 15 injuries, and 4,200 man-days lost.

3.8.1.4 Summary

Table 3-105 and Table 3-106 present a summary of the direct impacts associated with 250 MMscfd Lurgi and Synthane coal gasification facilities at Colstrip, Montana. Although these impacts will vary somewhat from location to location due to the type of coal used, meteorological conditions, etc., they are not expected to vary significantly between various sites in the western states.

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[1] Battelle-Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. EPA Contract No. 68-01-0470. Columbus, OH., 1973.

TABLE 3-105. SUMMARY OF IMPACTS ASSOCIATED WITH A 250 MMscfd LURGI COAL GASIFICATION PLANT AT COLSTRIP, MONTANA

Input Requirements	
Manpower	
• construction	10,781 man-years
• operating	589 men
Materials and Equipment	
• structural steel	14,000 tons
• piping	58,000 tons
• ready mixed concrete	180,000 tons
Economics[a]	
• capital costs	\$750 million
• operating costs	\$ 9.8 million
Water	9,263 acre-ft/yr
Land	800 acres
Ancillary Energy	None
Outputs	
Air Emissions	
• particulates	negligible
• SO_2	516 lb/hr
• NO_x	495 lb/hr
• HC	953 lb/hr
• CO	negligible
Water Effluent (plant)	
• to ash ponds	310 gpm
• to evaporation ponds	820 gpm
Solid Wastes	
• ash	225,000 lb/hr
• water treatment sludge	500 lb/hr
• spent catalyst	intermittent
Noise Pollution	negligible
Occupational Health and Safety	
• fatalities	0.45 deaths/yr
• accidents	15 injuries/yr
• man-days lost	4,200 man-days/yr

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[a] Third-quarter 1974 dollars

TABLE 3-106. SUMMARY OF IMPACTS ASSOCIATED WITH A 250 MMscfd SYNTHANE COAL GASIFICATION PLANT AT COLSTRIP, MONTANA

Input Requirements	
Manpower	
• construction	10,781 man-years
• operating	689 men
Materials and Equipment	
• structural steel	14,000 tons
• piping	58,000 tons
• ready mixed concrete	180,000 tons
Economics[a]	
• capital costs	$750 million
• operating costs	$ 9.8 million
Water	29,036 acre-ft/yr
Land	800 acres
Ancillary Energy	None
Outputs	
Air Emissions	
• particulates	8 lb/hr
• SO_2	3524 lb/hr
• NO_x	5052 lb/hr
• HC	1047 lb/hr
• CO	176 lb/hr
Water Effluent (plant)	
• to ash ponds	310 gpm
• to evaporation ponds	820 gpm
Solid Wastes	
• ash	180,000 lb/hr
• limestone sludge	110,000 lb/hr
• spent catalyst	intermittent
Noise Pollution	negligible
Occupational Health and Safety	
• fatalities	0.45 deaths/yr
• accidents	15 injuries/yr
• man-days lost	4,200 man-days/yr

[a] Third-quarter 1974 dollars

3.8.2 Liquefaction

3.8.2.1 Technology Description

3.8.2.1a Overview

Liquefaction is a conversion process that is designed to produce synthetic hydrocarbon liquids from coal. The growing divergence between domestic crude oil supplies and the domestic demand for liquid fuels and feedstocks has renewed interest in the development of technically and economically feasible means for converting coal to environmentally acceptable liquid fuels. Coal liquefaction is not a new technology but dates back to the early part of the twentieth century, and in principal even further than that.

During the nineteen-twenties and thirties, extensive research into the hydrogenation of coal was performed in Germany. German interest in liquid fuels stemmed from the fact that the nation had extensive coal reserves but no domestic petroleum. The United States Department of the Interior conducted small scale feasibility studies of the German technology but these efforts were abandoned with the East Texas oil discovery in 1930.

In 1944, during the latter part of the second World War, interest in coal liquefaction in the United States was renewed. In that year the Synthetic Fuels Act provided sixty million dollars to fund studies through 1955. Again, another large oil discovery, this time in the Middle East, reduced interest in liquid fuels from coal.[1]

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[1] Hittman Associates, Inc. Technology and Environmental Overview: Coal Liquefaction. Draft Final Report, for U.S. Environmental Protection Agency, Contract No. 68-02-2162. Columbia, Maryland: Hittman Associates, 1977. p. 4.

With the entry into an era of declining petroleum reserves, reduced discoveries, and escalating prices, coal liquefaction technology has once more assumed a major role as a potential solution to the liquid fuels problem.

The primary objective of coal liquefaction processes is to reduce the level of impurities and increase the hydrogen to carbon ratio of coal to the point that it is fluid. Coal has a hydrogen to carbon molar ratio of 0.8 to 1, while crudes and fuel oils have hydrogen to carbon molar ratios of 1.6 to 1 or greater. The essence of coal liquefaction is, therefore, to crack the coal molecule and either add hydrogen or remove carbon to increase the H:C ratio.

Currently there are over twenty coal liquefaction processes in various stages of development by both industry and federal agencies. However, these processes can be grouped into four basic liquefaction techniques.

- Indirect Liquefaction
- Pyrolysis
- Solvent Extraction
- Catalytic Liquefaction

Indirect Liquefaction

In the indirect liquefaction process, coal is gasified with steam and oxygen to produce a synthesis gas of carbon monoxide and hydrogen. These gases are purified and then reacted in the presence of catalyst to produce liquid products. Fischer-Tropsch and methanol synthesis are two examples of indirect liquefaction.[1]

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[1] National Research Council. Assessment of Technology for the Liquefaction of Coal. Committee on Sociotechnical Systems, National Research Council. Washington D.C.: National Academy of Sciences. 1977. Ch. 4.

While indirect liquefaction is the only liquefaction process practiced on a commercial scale, it does not appear promising for production of liquid fuels. The indirect liquefaction process requires complex plants with high capital costs. Also, thermal efficiencies are low (approximately 40 to 45 percent). Advantages of the indirect liquefaction process are that it performs equally well on any coal, there is a high degree of product control, it produces very clean fuels, and it has been demonstrated on a commercial scale outside the United States.[1]

Pyrolysis

In the pyrolysis process, the hydrogen to carbon ratio in the conversion products is increased by the removal of carbon. pyrolysis involves heating coal in the absence of air or oxygen to temperatures exceeding 400°C. At these temperatures the coal is cracked and converted to liquid and gaseous products high in hydrogen, and to char, a product containing almost no hydrogen. Char is primarily composed of carbon and ash.[2]

Of the pyrolysis processes, only the Lurgi-Ruhrgas process has reached the point of commercial development. The COED process has been developed through the pilot scale, and the Occidental process has been developed on a very small pilot scale.[3]

Although these pyrolysis processes have several distinct advantages, they do not appear attractive for the large scale production of liquid fuels. Advantages of the pyrolysis process are that it operates at low or atmospheric pressure, it is unnecessary to supply hydrogen, a synthesis gas, or oxygen to the process, the reaction times are relatively short, and the equipment is simple with a relatively low capital cost. Some of the significant disadvantages of the pyrolysis process are that only about one-third or less of the coal is converted to liquids, much of the liquid is very heavy and not easily separated from the char, the liquids will require hydrogenation to produce environmentally acceptable fuels, and there is a very uncertain market for the high volume of char produced in the process.[1]

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[1] National Research Council. Assessment of Technology for the Liquefaction of Coal. Committee on Sociotechnical Systems, National Research Council. Washington D.C.: National Academy of Sciences. 1977. Ch. 4.

[2] *Ibid.*

[3] *Ibid.*

Solvent Extraction

The solvent extraction coal liquefaction processes use a solvent generated in the process to transfer externally produced hydrogen to the coal. Pulverized coal is dissolved and reacted with the process derived donor solvent at approximately 752°F to 932°C and at pressures of 500 psi or more. The donor solvent is capable of transferring relatively loosely bound hydrogen atoms to the coal, maximizing the fraction of coal going into solution. Solvent extraction processes differ primarily in the location of hydrogen addition. Hydrogen may be added before or after extraction. The hydrogen required by the solvent extraction process may be made from the gasification of unconverted coal (char), gaseous products, raw coal, or a combination of the above. Solvent extraction processes have been developed through the 50 ton per day of coal pilot plant scale.[2]

Major advantages of the solvent extraction processes include high product yields (2 to 2.7 bbl/ton of coal), indifference to coal quality, flexibility of product slates, and substantial sulfur removal. Disadvantages of the solvent extraction process include problems with the separation of ash and unconverted coal from the liquid products, a solid product which is very friable and difficult to handle with conventional equipment, and limited knowledge about the preheating and handling of coal-solvent slurries.[1]

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[1] National Research Council. Assessment of Technology for the Liquefaction of Coal. Committee on Sociotechnical Systems, National Research Council. Washington D.C.: National Academy of Sciences. 1977. CH. 4.

[2] *Ibid.*

Solvent extraction processes yielding products which can be separated with vacuum distillation appear the most promising until solid-liquid separation devices are perfected for the difficult conditions of this use.

Catalytic Liquefaction

The catalytic liquefaction process differs from solvent extraction only in that hydrogen is added to the coal with the aid of a catalyst. Catalytic liquefaction hydrogenates coal in a process derived solvent using externally produced hydrogen in a manner very similar to the solvent extraction process. The catalyst may be located in a fixed bed or slurried in the donor solvent with the coal. Currently, catalytic liquefaction processes are being tested at the 1 ton of coal per day size and at the 3 ton of coal per day size.[2]

Advantages of the catalytic liquefaction process are its low operating pressures, short retention time, high degree of product quality control, and high liquid yields. However, catalytic liquefaction also has some significant disadvantages. Separation of the oil and catalyst from the undissolved coal and ash proves to be a very difficult problem at the elevated temperatures and pressures of the process. A second major problem is fouling and deactivation of the catalyst due to char and trace elements associated with the coal. Currently catalyst life is very short.

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[1] National Research Council. Assessment of Technology for the Liquefaction of Coal, Committee on Sociotechnical Systems, National Research Council. Washington, D.C.: National Academy of Sciences, 1977, Chapter 4.

[2] *Ibid.*

3.8.2.1b Description of SRC Technology

Solvent extraction processes and catalytic liquefaction processes exhibit the highest combination of thermal efficiency and liquid products yield. However, among these two technologies, solvent extraction appears to have the fewer engineering hurdles. Of the solvent extraction processes currently being developed, the Solvent Refined Coal (SRC) process has been demonstrated on the largest scale. Based on this information, the SRC process was selected to characterize the inputs and outputs from a coal liquefaction process.

Development Status[1]

The early work on the solvent refining of coal in solution under hydrogen pressure was carried out by A. Pott and H. Broche in Germany in the 1920's. The Pott-Broche process was utilized in Germany during World War II to manufacture a raw material for aluminum plant electrodes.

During the 1950's, research and development work on a modification of the Pott-Broche process was carried out by Spencer Chemical Company. In 1962, the Office of Coal Research (O.C.R.) awarded a research contract to Spencer Chemical to evaluate the technical feasibility of the Solvent-Refined Coal (SRC) process as it was then termed. This contract was concluded in 1965 upon the successful completion of the demonstration of the process in a 50 pound per hour continuous-flow process development unit. During the currency of this contract, Gulf Oil Corporation acquired Spencer Chemical Company and reassigned the SRC project to the Research and Development Department of The Pittsburgh and Midway Coal Mining Company (P&M).

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[1] Huffman, Everett L. "Operations at the Wilsonville SRC Plant," presented at the Third Annual International Conference on Coal Gasification and Liquefaction. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1976. p. 2.

In 1966, O.C.R. awarded a 9.5 year contract to P&M to continue research and development of the SRC process. This contract provides for a study of the commercial feasibility of the process through design, construction, and operation of a pilot plant to process 50 tons of coal per day.

The Stearns-Roger Corporation completed the design of the pilot plant in 1969. A shortage of funds delayed the start of construction until 1972, when a contract for the detailed engineering and construction of the pilot plant was awarded to Rust Engineering Co. of Birmingham, Ala. Field construction was underway in July, 1972, with completion and preliminary start-up in mid-October, 1974. Studies are now being carried on at this pilot plant in Ft. Lewis, Washington.

A joint SRC pilot plant program is also being conducted by the Edison Electric Institute and the Southern Company system to study the key steps in the SRC process. The 6 ton per day plant was built on the site of the Alabama Power Company's Ernest C. Gaston Steam Plant located near Wilsonville, Alabama.

Catalytic, Inc. designed, built, and is operating this pilot plant which began operation in 1974. The Electric Power Research Institute and the U.S. Energy Research and Development Administration have now assumed joint sponsorship of the pilot plant operation.

Design Parameters

A process flow diagram for the SRC-II process is presented in Figure 3-27. The SRC-II process is a second generation SRC process designed to maximize the production of liquid fuels. The plant size selected for this study has an output equivalent to the output of a 100,000 barrels per day (bpd) oil refinery on a Btu basis. The raw coal feed rate for this size facility is approximately 30,000 tons per day (tpd).[1]

The SRC plant is also designed to be relatively selfsufficient with respect to utilities and hydrogen supply. Selfsufficiency will be required for conversion plants located at remote western coal fields. A gasification unit is included for the production of process hydrogen from char and undissolved coal in the vacuum bottom residue. A utility boiler is provided to supply steam demands, and a raw water treatment plant is included for producing process water. The low quality fuel gas produced by the SRC process is applied internally to the production of process heat.

The primary portion of SRC-II information presented in this technology description has been developed from published information on the Ft. Lewis Washington SRC pilot plant. The Ft. Lewis plant has a capacity of 50 tons per day of coal and has operated successfully since 1974. However, this facility is not a completely integrated SRC coal conversion plant. Vacuum bottom gasification is not being conducted at this pilot plant. Consequently, some of the published information used in this report is based on either engineering designs of a commercial scale SRC

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[1] Schmid, B.K., D.M. Jackson. "Recycle SRC Processing for Liquid and Solid Fuels." Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1977. p. 5.

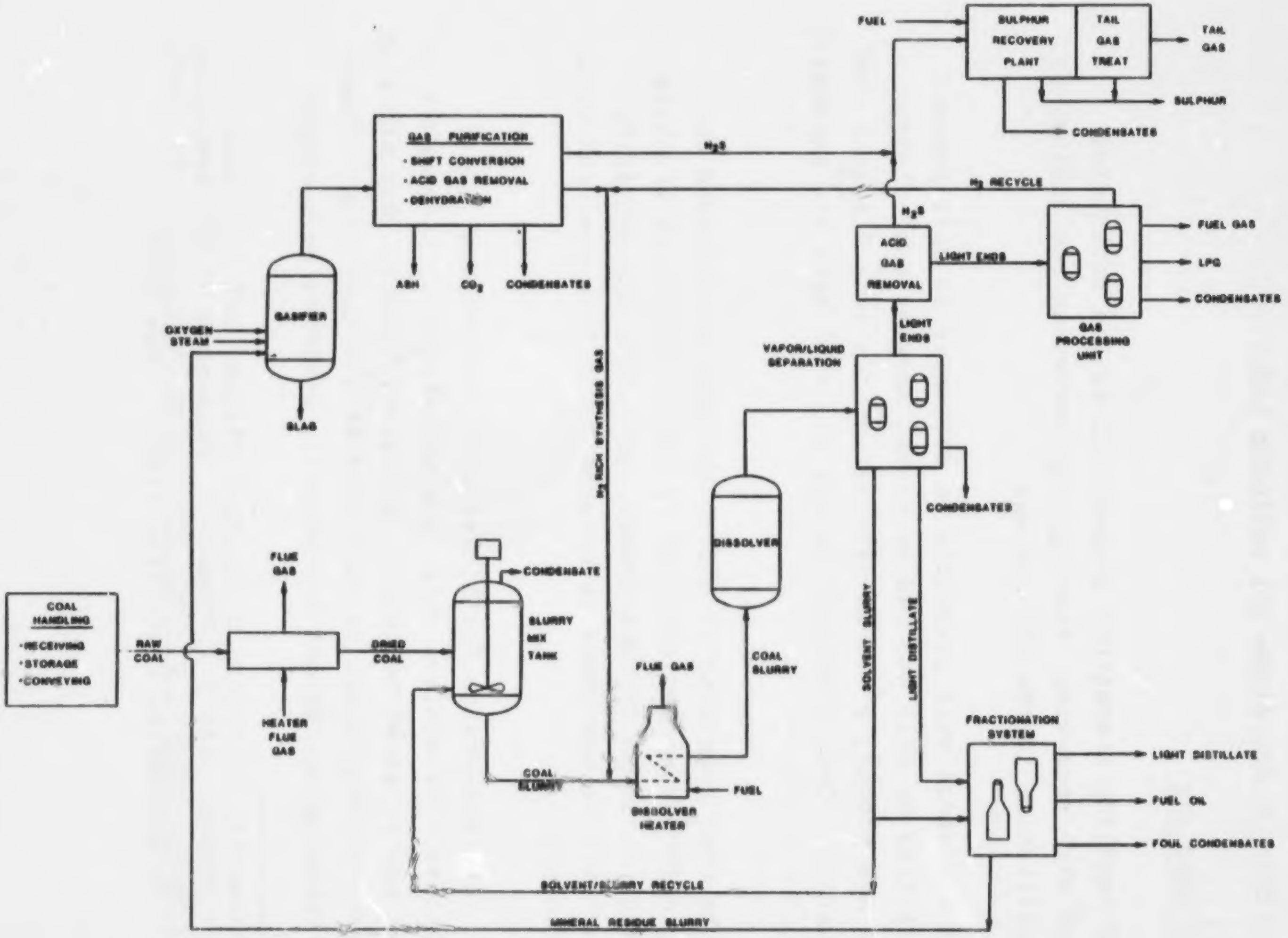
FUEL
SULPHUR RECOVERY PLANT
TAIL GAS TREAT
TAIL GAS
SULPHUR
CONDENSATES
GAS PURIFICATION
• SHIFT CONVERSION
• ACID GAS REMOVAL
• DEHYDRATION
H_2S
H_2 RECYCLE
H_2S
ACID GAS REMOVAL
LIGHT ENDS
FUEL GAS
LPG
CONDENSATES
GAS PROCESSING UNIT
ASH
CO_2
CONDENSATES
OXYGEN
STEAM
GASIFIER
SLAG
H_2 RICH SYNTHESIS GAS
LIGHT ENDS
VAPOR/LIQUID SEPARATION
CONDENSATES
DISSOLVER
COAL HANDLING
• RECEIVING
• STORAGE
• CONVEYING
RAW COAL
FLUE GAS
HEATER FLUE GAS
DRIED COAL
CONDENSATE
SLURRY MIX TANK
FLUE GAS
COAL SLURRY
COAL SLURRY
FUEL
DISSOLVER HEATER
SOLVENT SLURRY
LIGHT DISTILLATE
FRACTIONATION SYSTEM
LIGHT DISTILLATE
FUEL OIL
FOUL CONDENSATES
SOLVENT/SLURRY RECYCLE
MINERAL RESIDUE SLURRY

Figure 3-27. Example Flow Diagram for a SRC-II Coal Liquefaction Process

facility or on information from comparable processes in both the coal liquefaction and crude oil refining industry.

Coal Handling

Coal handling operations include all of the activities associated with receiving, storing, and conveying raw coal prior to its utilization in the SRC process.

Coal feedstock will primarily be delivered to coal conversion facilities by rail car and by truck; however coal slurry pipelines are proving a viable alternative for long distance coal transportation. Coal transport trucks and rail cars are generally uncovered.[1]

At the coal receiving facility, the coal is unloaded into an underground hopper and conveyed by belt conveyer to crushing operations. Based on current trends, unloading and conveying operations will be contained in covered facilities equipped with dust collectors.[2]

Most coal conversion facilities will require coal sizes below 2 inches. To achieve this, the incoming coal is crushed in two stages and screened to recycle oversized chunks. Occasionally the primary crushing stage is performed at the mine site. Crushing and screening operations are normally enclosed in a single structure equipped with dust collectors.[1]

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[1] Farnsworth, J. Frank, D. Michael Mitsak, and J.F. Kamody. "Clean Environment with K-T Process." Presented at EPA Symposium on Environmental Aspects of Fuel Conversion Technology. St. Louis, Missouri: Environmental Protection Agency. May 1974.

[2] *Ibid.*

Crushed coal is conveyed by covered belt conveyers to active storage bins. These bins have two or more days storage capacity and tend to serve largely as surge capacity. Active storage bins are also enclosed and equipped with dust collectors.[2]

A large supply of coal is often set aside in dead storage to be used for emergencies only. The size of this supply is typically 60 days of feedstock, but can be much smaller. The dead storage pile is prepared on an impervious base in compacted layers to an average total height of 25 ft. To seal against wind and water, dead storage piles are often sprayed with asphalt or polymer crusting agents.[3]

Coal Preparation

Coal preparation consists of drying the raw coal to 3 wt % moisture and grinding it to a size between 1/8 inch and 200 mesh.[4] The natural moisture content of western coals can range from less than 4 wt % to approximately 40 wt %. Drying and grinding operations can be performed either simultaneously in wind-swept mills or in separate dryers and pulverizers. The drying is effected by contact with flue gas from either the dissolver heater or a separate heater designed expressly for coal drying. Tight temperature control insures the coal temperature does not exceed 185°F to 195°F, thus preventing devolatilization of the coal.[1]

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[1] Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process. Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company. March 1975. p. 12.

[2] Farnsworth, J. Frank, D. Michael Mitsak, and J.F. Kamody. "Clean Environment with K-T Process." Presented at EPA Symposium on Environmental Aspects of Fuel Conversion Technology. St. Louis, Missouri: Environmental Protection Agency. May 1974.

[3] Jahnig, C.E. *op.cit.*

[4] (Ralph M.) Parsons Company. Demonstration Plant Clean Boiler Fuels From Coal. Office of Coal Research R&D Report 82, Int. Rpt. 1, 3 Volumes, Contract No. 14-32-0001-1234. Los Angeles, California: Ralph M. Parsons Company. September 1973.

Coal is conveyed by belt to the grinding operation. All subsequent coal conveying is performed pneumatically using recycle nitrogen from the oxygen plant. Nitrogen blankets are also used on all coal storage bins.[2]

Drying, grinding and conveying operations are enclosed and equipped with dust collectors to minimize particulate emissions.[3]

Coal Dissolution

Prepared coal is conveyed to a slurry mix tank where it is mixed with infiltered recycle solvent to form a 40 wt % slurry.[4]

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[1] Pittsburgh & Midway Coal Mining Company. Development of a Process for Producing an Ashless, Low-Sulfur Fuel From Coal. Vol III - Pilot Plant Development Work. Part 2 - Construction of Pilot Plant. Energy Research and Development Administration, R&D Rept. 53, Int. 9, FE 496 T2. Fort Lewis, Washington: Pittsburgh & Midway Coal Mining Company. May 1975.

[2] (Ralph M.) Parsons Company. Demonstration Plant Clean Boiler Fuels From Coal. Office of Coal Research R&D Report 82, Int. Rpt. I, 3 Volumes, Contract No. 14-32-0001-1234. Los Angeles, California: Ralph M. Parsons Company. September 1973.

[3] Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process. Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company. March 1975. p. 22.

[4] Huffman, Everett L. "Operations at the Wilsonville SRC Plant." Presented at the Third Annual International Conference on Coal Gasification and Liquefaction. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1976. p. 19.

The recycling of unfiltered solvent improves product yield and product quality. These improvements are attributable to catalytic properties of the coal ash and to the reprocessing of undissolved organic material.[1] Remaining moisture in the coal is partially evaporated in the slurry mix tank and vented to a condenser.[2]

Coal slurry from the slurry mix tank is pressured to 1000 psig-2000 psig and mixed with hydrogen-rich synthesis gas from the gasifier.[3,4] After addition of synthesis gas, the coal slurry is heated in the dissolver heater to temperatures ranging from 700°F to 750°F. At this time the coal is already partially dissolved in the recycle slurry "solvent", and the exothermic reactions of hydrogenation and hydrocracking have just begun.[5]

From the dissolver heater the coal slurry enters the dissolver where the hydrocracking and hydrogenation reactions continue. Quench hydrogen must be added to the dissolver to alleviate the effect of these exothermic reactions, and to maintain dissolver temperatures in the range of 820°F to 870°F.[6]

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[1] Huffman, Everett L. "Operations at the Wilsonville SRC Plant." Presented at the Third Annual International Conference on Coal Gasification and Liquefaction. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1976. p. 3.

[2] Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process. Final Report for U.S. Environmental Protection Agency. Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company. March 1975. p. 22.

[3] *Ibid.*

[4] Huffman, Everett L., *op. cit.*, p. 19.

[5] Schmid, B.K., D.M. Jackson. "Recycle SRC Processing For Liquid and Solid Fuels." Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1977. p. 8.

[6] *Ibid.*

During the dissolution and hydrogenation process, large portions of the oxygen and primarily non-ring organic sulfur in the coal are hydrogenated to H_2O and H_2S. A small portion of the nitrogen in the coal is converted to NH_3.[1]

Product Separation

The dissolver effluent is separated into several product streams by a series of flash separators and condensers. The non-condensed gases from this separation consist of unreacted hydrogen, methane, light hydrocarbons, H_2S, and CO_2. These gases are sent to the gas processing unit.[2]

Hydrocarbon liquids and coal-solvent slurry recovered from the separators and condensers are further separated in a fractionation system. Atmospheric distillation and vacuum distillation are used in the fractionation system to separate the products into a light distillate fraction, a fuel oil fraction, and a mineral residue slurry. The light distillate fraction and the fuel oil fraction are low sulfur fuels requiring no further processing. The mineral residue slurry consists of undissolved coal, ash, and a very high boiling hydrocarbon fraction. This product is used for gasifier feed. Prior to fractionation, a portion of the coal-solvent slurry was withdrawn and recycled to the slurry mix tank.[3]

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[1] National Research Council. Assessment of Technology for the Liquefaction of Coal. Committee on Sociotechnical Systems, National Research Council. Washington D.C.: National Academy of Sciences. 1977.

[2] Huffman, Everett L. "Operations at the Wilsonville SRC Plant." Presented at the Third Annual International Conference on Coal Gasification and Liquefaction. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1976. p. 7.

[3] *Ibid.*, p. 8.

Gas Processing

Noncondensed gases from the product separation processes are first sent to an acid gas treating unit for removal of H_2S and CO_2. In the acid gas removal unit, feed gas is first contacted with diethanolamine (DEA) where the H_2S and CO_2 in the feed gas are chemically absorbed by the DEA solution. The DEA solution is subsequently regenerated by distilling or stripping off the H_2S and CO_2. The H_2S and CO_2 are then routed to a sulfur recovery unit.[1]

Treated gases from the acid gas treating unit are subsequently separated in the gas processing unit by using cryogenic condensation and fractionation. Products from the gas processing unit include fuel gas, liquid petroleum gases (LPG), and a hydrogen-rich recycle stream. The hydrogen recycle stream is returned to the dissolver heater. The low sulfur fuel gas may be used for plant fuel or sold as pipeline gas.[2]

Synthesis Gas Production

The hydrogen-rich synthesis gas required by the SRC process is manufactured on-site in an oxygen-blown gasifier. Gasifier feed is expected to be the mineral residue slurry withdrawn from the product fractionation section. This mineral residue slurry is composed of undissolved coal, ash, and a very high boiling hydrocarbon fraction. Normally this stream will be sufficient to supply gasifier feed requirements. If not the case, undersized and oversized coal from the drying and grinding operation and raw coal can be added to the gasifier feed.[1]

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[1] Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process. Final Report for U.S. Environmental Protection Agency. Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company. March 1975. p. 24.

[2] Huffman, Everett L. "Operations at the Wilsonville SRC Plant." Presented at the Third Annual International Conference on Coal Gasification and Liquefaction. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1976. p. 7.

In the gasifier, the mineral residue slurry is partially combusted to H_2, CO, H_2O, H_2S, NH_3, CO_2, and minor quantities of other combustion products. After passing through waste heat recovery, the gasifier products are processed to form a hydrogen-rich synthesis gas. Typical gas purification processes include particulate removal, absorption of H_2S, CO_2, and NH_3, water removal and shift conversion. In the shift conversion process, CO and H_2O are catalytically reacted to form CO_2 and additional H_2.[2]

The CO_2 removed from the gasifier is normally vented to the atmosphere. The H_2S and NH_3 are routed to the sulfur recovery plant. Condensates are sent to a sour water stripper and recovered coal ash is landfilled with other solid wastes from the plant.[3]

Auxiliary Facilities[4]

Several auxiliary facilities will be required by an SRC coal liquefaction plant to perform utility and support functions:

- oxygen plant
- wastewater treatment
- sulfur recovery plant

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[1] Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process. Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company. March 1975. p. 24.

[2] *Ibid.*

[3] *Ibid.*

[4] *Ibid.*, Ch. 4.

- cooling water system
- utility power plant
- process water treating

Oxygen for the mineral residue gasifier is supplied by an on-site oxygen plant. The oxygen plant recovers oxygen and nitrogen from the atmosphere using cryogenic separation processes. The nitrogen recovered by the oxygen plant is used to blanket coal storage and handling operations.

Water effluents generated by condensate systems and collected from process drains are sent to a wastewater treating facility. The wastewater treating facility encompasses sour water stripping, soluble oil removal, and conventional wastewater treatment. The sour water stripper employs a steam stripping process to remove H_2S and NH_3 from wastewaters. The H_2S is routed to the sulfur recovery plant and the recovered NH_3 is salable as anhydrous liquid ammonia. Phenolics and cresylics are dissolved in the wastewater to excessive levels and cannot be treated by conventional biological processes. These oxygenated compounds are removed from the wastewater by absorption in a lean oil.

All H_2S streams generated within the SRC plant are routed to the sulfur recovery plant where the hydrogen sulfide is recovered as elemental sulfur. The Claus process is the most common process used for sulfur recovery. Residual sulfur in the tail gas from the sulfur recovery plant is further recovered in a tail gas treatment unit. The treated tail gas is subsequently vented to the atmosphere.

Cooling water for the SRC plant is provided by a conventional cooling water system. In the cooling water system, cool water is circulated to plant coolers and condensers where it absorbs process heat. Warm cooling water is returned to central cooling towers where the absorbed heat is released to the atmosphere by direct contact evaporation. The cooled cooling water is then recycled to the SRC processes.

The steam required for operating the SRC plant is supplied by a utility power plant. Fuel needs for the utility power plant are supplied by combusting the low sulfur fuel gas produced by the process. Other potential fuel sources include low sulfur coal or one of the low sulfur SRC fuel oils.

Depending on the quality and end use, raw water for the SRC plant must go through some degree of treatment in the process water treating unit. Process water treating often involves filtering and lime treatment to precipitate hardness. Flocculating agents are sometimes added to promote precipitation. Treated water is clarified; the sludge is disposed with gasifier ash and slag. Boiler feed water goes through the additional clean-up of cation and anion exchange, deaeration heaters, and additional chemical treatment.

3.8.2.2 Input Requirements

This section reports the input requirements for an SRC-II coal liquefaction facility sized for a coal feed rate of approximately 30,000 tons per day. The output from such a facility will have an output equivalent to a modern 100,000 bpd refinery on a Btu basis. Table 3-107 lists the estimated product flow rates for a typical 30,000 tpd SRC-II plant. Information from Gulf Minerals Co. on their 50 ton per day pilot indicates that general input requirements will not vary greatly among the various SRC process designs being developed by Gulf Mineral Resources Co. This trend probably holds true for all the various solvent extraction and catalytic liquefaction processes.[1]

TABLE 3-107. ESTIMATED NET PRODUCT FLOW RATES FOR A TYPICAL 30,000 TPD SRC-II PLANT

Products	Rate
Pipeline gas (10^6 scf/d)	36
LPG (bpd)	7,700
Light oil (bpd)	15,600
Fuel oil (bpd)	63,500

Source: Schmid, B.K., D.M. Jackson. "Recycle SRC Processing for Liquid and Solid Fuels." Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1977. p. 4.

3.8.2.2a Manpower

Estimated manpower requirements for the construction and operation of a 30,000 tpd coal liquefaction facility are presented in Table 3-108 and Table 3-109 respectively. These estimates were developed by Radian Corporation using Bechtel Corporation's "Energy Supply Planning Model." The Energy Supply Planning Model is a computer simulation model developed by Bechtel Corporation based on the extensive construction experience of their Operating Divisions. Bechtel Corporation reports that the accuracy of

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[1] Schmid, B.K., D.M. Jackson. "Recycle SRC Processing for Liquid and Solid Fuels." Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1977. p. 23.

TABLE 3-108. SCHEDULE OF MANPOWER REQUIREMENTS FOR CONSTRUCTION OF A 30,000 TPD COAL LIQUEFACTION FACILITY

	Manpower Requirements (man-years)						
Skill	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7
Chemical Engineers	6	48	126	150	99	54	18
Civil Engineers	6	57	147	177	120	63	21
Electrical Engineers	6	51	132	159	105	57	21
Mechanical Engineers	9	66	180	216	144	75	27
Other Engineers	3	18	48	57	39	21	6
Total Engineers	33	237	633	759	507	270	96
Total Designers & Draftsmen	24	174	462	552	369	195	69
Total Supervisors & Managers	3	30	78	93	63	33	12
Total Technical	60	438	1173	1407	939	498	177
Total Non-Tech. (non-manual)	21	147	390	468	312	165	60
Pipefitters	0	48	327	891	1266	939	282
Pipefitters/Welders	0	15	108	297	423	312	93
Electricians	0	21	138	372	528	390	117
Boilermakers	0	12	81	222	315	234	69
Boilermakers/Welders	0	3	15	36	54	39	12
Iron Workers	0	12	81	222	315	234	69
Carpenters	0	15	108	297	423	312	93
Operating Engineers	0	9	54	147	210	156	48
Other Major Skills	0	3	15	36	54	39	12
Total Major Skills	0	132	930	2523	3585	2655	798
Other Craftsmen	0	30	219	594	843	624	189
Total Craftsmen	0	165	1149	3117	4431	3282	984
Total Teamsters & Laborers	0	30	219	594	843	624	189
Total Labor Force	81	780	2931	5586	6525	4569	1410

Source: Carasso, M., *et al.* The Energy Supply Model, Vol. I: Model Structure and Use, Bechtel Corporation, Final Report to The National Science Foundation, Contract No. NSF-C867. San Francisco, California: Bechtel Corporation, August 1975.

TABLE 3-109. MANPOWER REQUIREMENTS FOR OPERATION OF A 30,000 TPD COAL LIQUEFACTION FACILITY

Skill	No. of People
Chemical Engineers	22
Civil Engineers	5
Electrical Engineers	2
Mechanical Engineers	10
Other Engineers	2
Total Engineers	41
Total Designers & Draftsmen	5
Total Supervisors & Managers	65
Total Other Technical	30
Total Technical	141
Total Non-tech. (non-manual)	147
Pipefitters	90
Electricians	50
Boilermakers	32
Carpenters	25
Equipment Operators	15
Other Operators	448
Welders, unclassified	60
Other Major Skills	247
Total Major Skills	967
Other Craftsmen	154
Total Craftsmen	1121
Total Teamsters & Laborers	179
Total Operating Staff	1588

Source: Carasso, M., *et al*. The Energy Supply Model, Vol. I: Model Structure and Use, Bechtel Corporation, Final Report to the National Science Foundation, Contract No. NSF-C867. San Francisco, California: Bechtel Corporation, August 1975.

these estimates are approximately -30 percent/+75 percent.[1]

Table 3-108 indicates that construction manpower requirements during the first year's activity will be approximately 80 people, most of whom are engineers, designers and draftsmen. Manpower requirements rise dramatically the second year and reach a peak of approximately 6500 people in the fifth year of construction. Total construction time is estimated to be seven years.

Table 3-109 indicates that approximately 1600 people are required for operating a 30,000 tpd coal liquefaction plant. This total includes 300 technical and nontechnical (non-manual) people, 1100 craftsmen, and 200 non-craftsmen.

3.8.2.2b Materials and Equipment

Materials and equipment requirements for the construction and operation of a 30,000 ton per day SRC coal liquefaction plant are presented in Table 3-110 and Table 3-111 respectively. The construction material and equipment requirements were developed by Radian Corporation using Bechtel's "Energy Supply Model" computer program. The Energy Supply Model is based on the extensive construction experience of their Operating Divisions. Bechtel Corporation reports that the accuracy of these estimates

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[1] Carasso, M., *et. al.* The Energy Supply Model, Vol I: Model Structure and Use. Bechtel Corporation. Final Report to the National Science Foundation, Contract No. NSF-C867. San Francisco, California: Bechtel Corporation. August 1975. pp. 6-30.

TABLE 3-110. SELECTED MAJOR MATERIALS AND EQUIPMENT REQUIRED FOR CONSTRUCTION OF A 30,000 TPD COAL LIQUEFACTION PLANT

Materials	Quantities
Refined Products (tons)	48,000
Cement (tons)	36,000
Ready Mix Concrete (tons)	288,000
Pipe & Tubing (less than 24" D, tons)	60,000
Pipe & Tubing (24" D and greater, tons)	6,000
Structural Steel (tons)	26,000
Reinforcing Bars (tons)	9,000
Valves (24" D & greater, items)	6,000
Valves (24" D & greater, tons)	1,000
Steam Turbogenerator Sets (1000 hp)	300
Pumps & Drives (100 hp, items)	600
Pumps & Drives (100 hp, tons)	5,000
Compressors & Drives (1000 hp, items)	150
Compressors & Drives (1000 hp, tons)	40,000
Heat Exchangers (1000 sq. ft. surface area)	10,000
Pressure Vessels (1½" plate, tons)	45,000
Boilers (10^6 Btu/hr)	60,000

Source: Carasso, M., *et al.* The Energy Supply Model, Vol I: Model Structure and Use, Bechtel Corporation, Final Report to The National Science Foundation, Contract No. NSF-C867. San Francisco, California: Bechtel Corporation, August 1975.

TABLE 3-111. MAJOR MATERIALS REQUIRED FOR OPERATION OF A 30,000 TPD COAL LIQUEFACTION PLANT

Materials	Quantities
Monoethanolamine (lb/day)	12,000-40,000
Corrosion Inhibitor (gal/day)	150
Antifoam (gal/day)	20-50
Sodium Hydroxide (lb/day)	1020
Active Carbon (lb/day)	150-300
Shift Catalyst (ft^3/yr)	7200
BSRP CoMo Catalyst (ft^3/3 yr)	2300
Sulfur Recovery Catalyst (ft^3/3 yr)	15,000
Stretford Solution Makeup ($/day)	1200
Corrosion Inhibitor (lb/day)	100
Polymer Dispersant (lb/day)	100
Sulfuric Acid (lb/day)	10,000
Chlorine (lb/day)	5300
Phosphate Polymer Antifoam (lb/day)	1100
Hydrazine (lb/day)	8
Lime (lb/day)	6200
Aluminum Sulfate (lb/day)	3900
Caustic Soda (lb/day)	6400

Source: (Ralph M.) Parsons Company. Demonstration Plant. Clean Boiler Fuels From Coal, Office of Coal Research R&D Report 82, Int. Rpt. 1, 3 Volumes, Contract No. 14-32-0001-1234. Los Angeles, California: Ralph M. Parsons Company, September 1973, p. 28.

are approximately -30 percent/+75 percent.[1] Table 3-110 indicates that construction materials and equipment consist of over 200,000 tons of fabricated steel, 288,000 tons of concrete, and over 50,000 tons of refined products.

The operating materials listed in Table 3-111 were scaled from a 10,000 tpd coal liquefaction plant design developed by The Ralph M. Parsons Company. The Ralph M. Parsons design is a detailed preliminary plant designed based upon the research data collected by Pittsburgh & Midway Mining Company up through 1973.[2] No reliability values are available for these estimates.

3.8.2.2c Economics

Capital investment costs for an SRC-II coal liquefaction plant are presented in Table 3-112. These cost estimates are developed by Gulf Mineral Resources Co. from conceptual designs of a 30,000 tpd SRC-II plant.[3]

The total plant investment cost is estimated to be 1.05 billion dollars. In addition to the normal estimating contingency, a second contingency factor must be applied to account for these estimates being based on the preliminary design of a first-of-a-kind system. This contingency will add $100 million

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[1] Carasso, M., *et. al.* The Energy Supply Model, Vol I: Model Structure and Use. Bechtel Corporation. Final Report to The National Science Foundation, Contract No. NSF-C867. San Francisco, California: Bechtel Corporation. August 1975. pp. 6-30.

[2] (Ralph M.) Parsons Company. Demonstration Plant Clean Boiler Fuels From Coal. Office of Coal Research R&D Report 82, Int. Rpt. 1, 3 Volumes, Contract No. 14-32-0001-12334. Los Angeles, California: Ralph M. Parsons Company. September 1973. p. 1.

[3] Schmid, B.K., D.M. Jackson. "Recycle SRC Processing For Liquid and Solid Fuels." Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1977. p. 30.

TABLE 3-112. CAPITAL INVESTMENT COSTS FOR SRC-II PLANT
(1976 Dollars)

Item	Cost ($\$10^6$)
SRC-II Systems	
coal preparation	81
hydrogenation/dissolution	276
hydrogen recycle	91
fractionation	22
hydrogen plant	277
gas processing	117
utilities and off-sites	114
general facilities	76
Total Plant Investment	1054
Contingency Cost	
@ 10%	105
@ 20%	211
Other Capital Costs	79

Note: Feed Rate, 30,000 TPD; Product Output, 205 x 10^{12} Btu/yr.

Source: Schmid, B. K., D. M. Jackson. "Recycle SRC Processing For Liquid and Solid Fuels," Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh, August 1977, p. 34.

to $200 million to the total plant investment. Additional capital costs including land, working capital, start-up costs, catalysts, chemicals, and licensing costs will add another $80 million dollars to the total investment cost. Net capital cost for an SRC-II facility is estimated to be approximately $1.2 to $1.3 billion (in 1976 dollars).[1]

Operating cost estimates for a 30,000 tpd SRC-II plant are presented in Table 3-113. The total operating cost and coal costs were developed by Gulf Mineral Resources Co. based on the conceptual design of a 30,000 tpd SRC-II plant.[2] The operating cost breakdown was proportioned from operating cost data supplied by the Bureau of Mines based on the conceptual design of a 34,000 tpd SRC-I plant.[3]

The data in Table 3-113 indicates that the net annual operating cost of $302 million is very dependent on the cost of coal. Plant operating costs excluding coal costs are estimated to be $83 million per year. At $20/ton, annual coal costs are estimated to be $219 million.

The required selling price of products from an SRC-II plant is presented in Table 3-114. Again, these costs were developed by Gulf Mineral Resources Co. based on the conceptual design of

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[1] Schmid, B.K., D.M. Jackson. "Recycle SRC Processing For Liquid and Solid Fuels." Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1977. p. 30.

[2] *Ibid.*, p. 34.

[3] Bureau of Mines. Preliminary Economic Analysis of SRC Liquid Fuels Process, Producing 50,000 bpd of Liquid Fuels From Two Coal Seams: Wyodak And Illinois No. 6. Process Evaluation Group report for U.S. Energy Research and Development Administration. Morgantown, West Virginia: U.S. Government Printing Office. March 1976. p. 31.

TABLE 3-113. OPERATING COSTS FOR SRC-II PLANT
(1976 Dollars)

Item	Cost ($\$10^6$/yr)
Raw materials and utilities	7
Direct Labor	2
Plant maintenance	33
Payroll Overhead and Operating Supplies	11
Indirect Costs (G&A)	17
Fixed Cost (taxes and insurance)	13
Plant Operating Costs (excluding coal)	83
Coal Costs ($20/T. dry basis)	219
Net Operating Cost	302

Note: Feed Rate, 30,000 tpd; Product Output, 205×10^{12} Btu/yr

Sources: Schmid, B.K., D.M. Jackson. "Recycle SRC Processing For Liquid and Solid Fuels." Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1977. p. 34.

Bureau of Mines. Preliminary Economic Analysis of SRC Liquid Fuels Process, Producing 50,000 bpd of Liquid Fuels From Two Coal Seams: Wyodak and Illinois No. 6. Process Evaluation Group report for U.S. Energy Research and Development Administration. Morgantown, West Virginia: U.S. Government Printing Office. March 1976. p. 31.

TABLE 3-114. REQUIRED SELLING PRICE FOR INVESTMENT RETURN (1976 Dollars)

Investment Return	Price - $\$/10^6$ Btu 10% Contingency	 20% Contingency
Constant Dollars (0% escallation)		
12% DCF	3.07	3.21
15% DCF	3.55	3.69
Current Dollars (6% escallation)		
12% DCF	2.38	2.45
15% DCF	2.69	2.76

Basis:		
Basis:	Equity Funding	100%
	Return on Equity	12%, 15%
	Tax Rate	50%
	Investment Tax Credit	10%
	Life	20 years
	Depreciation	Straight Line
	Escallation	0%, 6%

DCF - Discounted Cash Flow

Source: Schmid, B.K., D.M. Jackson. "Recycle SRC Processing For Liquid and Solid Fuels." Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1977. p. 37.

a 30,000 tpd SRC-II plant. For this study LPG, pipeline gas, and fuel oil have been valued equally on a Btu basis and no credit has been applied for the value of sulfur or phenols recovered from the wastewater.[1]

While none of these parameters are specifically recommended, they do indicate that SRC fuels could be available commercially, following large-scale demonstration, for a cost in the order of $\$3/10^6$ Btu. This is equivalent to approximately \$18-20/barrel.

3.8.2.2d Water

Water consumption estimates for a typical 30,000 tpd SRC-I plant range from 15 to 29 million gallons per day.[2] Water consumption estimates for a 30,000 tpd SRC-II plant are expected to be equivalent. A breakdown of water uses is presented in Table 3-115.

TABLE 3-115. WATER CONSUMPTION FOR A 30,000 TPD SRC PLANT

Consumer	Consumption Rate (10^6 gal/day)
Process water	1
Boiler feed water makeup	2
Potable water	1
Cooling tower makeup	13
Total	17

Source: (Ralph M.) Parsons Company. Demonstration Plant. Clean Boiler Fuels From Coal. Office of Coal Research R&D Report 82, Int. Rpt. I, 3 Volumes, Contract No. 14-32-0001-1234. Los Angeles, California: Ralph M. Parsons Company. September 1973. p. 27.

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[1] Schmid, B.K., D.M. Jackson. "Recycle SRC Processing For Liquid and Solid Fuels." Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1977. p. 37.

[2] National Research Council. Assessment of Technology for the Liquefaction of Coal. Committee on Sociotechnical Systems, National Research Council. Washington D.C.: National Academy of Sciences. 1977.

These water consumptions are scaled from a 10,000 tpd SRC plant design developed by Ralph M. Parsons Company. This preliminary plant design assumes a conventional level of water recycle and reuse.[1]

In a study on water conservation and pollution control, Water Purification Associates determined that net water consumption by unrecoverable systems (*i.e.*, evaporation, dust control, chemical reaction, etc.) is approximately 3 to 4 million gallons per day for a 30,000 tpd SRC plant.[2] This represents the minimum water consumption achievable by applying maximum water recycle and reuse.

3.8.2.2e Land Area

Based on a preliminary plant design, Ralph M. Parsons Company estimates the minimum land area required to establish a 30,000 tpd SRC plant to be 1050 acres. However, a site of 1800 acres or more is recommended as much more desirable. These estimates include land area for coal yards and solid waste disposal.[3]

3.8.2.2f Ancillary Energy

The ancillary energy requirements for an SRC-II coal liquefaction facility are highly dependent on the designer's choice of power sources. In the conceptual design of a 10,000 tpd SRC plant, Ralph M. Parsons estimated the average electrical energy consumption to be 76 MW.[1] The design basis 30,000 tpd SRC-II plant would consume an estimated 228 MW of electrical power. This is considered to be a large enough electrical demand to justify electrical generation facilities on site fueled with low quality fuel gas.

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[1] (Ralph M.) Parsons Company. Demonstration Plant. Clean Boiler Fuels From Coal. Office of Coal Research R&D Report 82, Int. Rpt. 1, 3 Volumes, Contract No. 14-32-0001-1234. Los Angeles, California: Ralph M. Parsons Company. September 1973. p. 27.

[2] Water Purification Associates. Water Conservation and Pollution Control in Coal Conversion Processes. Final Report for the U.S. Environmental Protection Agency, Contract No. 68-03-2207. Cambridge, Mass: Water Purification Associates. July 1977. p. 106.

[3] (Ralph M.) Parsons Company. *op.cit.*,

Gulf Mineral Resources Company in a recently completed conceptual design of a 30,000 tpd SRC-II plant, estimated that electrical energy consumption would be 41 MW.[2] This significantly lower electrical energy consumption is attributable to their use of steam drives where possible. This is a low enough energy consumption that they would likely purchase this power from off-site and up-grade their fuel gas to a valuable product.

3.8.2.3 Outputs

The outputs associated with a liquefaction facility are dependent on site, size, feedstock, processing scheme, and product mix. The outputs herein developed for this study are for a hypothetical 30,000 tpd SRC-II coal liquefaction facility located near Gillette, Wyoming. This facility has an output equivalent to a modern 100,000 bpd oil refinery on a Btu basis.[3]

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[1] (Ralph M.) Parsons Company. Demonstration Plant. Clean Boiler Fuels From Coal. Office of Coal Research R&D Report 82, Int. Rpt. 1, 3 Volumes, Contract No. 14-32-0001-1234. Los Angeles, California: Ralph M. Parsons Company. September 1973. p. 21.

[2] Huffman, Everett L. "Operations at the Wilsonville SRC Plant." Presented at the Third Annual International Conference on Coal Gasification and Liquefaction. Pittsburgh, Pennsylvania: University of Pittsburgh. August 1976. p. 11.

[3] Schmid, B. K., D. M. Jackson. "Recycle SRC Processing for Liquid and Solid Fuels", Fourth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity. Pittsburgh, Pennsylvania: University of Pittsburgh, August 1977, p. 23.

Table 3-107 lists the estimated product flow rates for this facility. A Wyoming subbituminous coal from the Powder River coal field was used for the feed stock. An analysis of Powder River coal is presented in Table 3-116.

The SRC-II process has been described in Section b of 3.8.2.1. A self-sufficient SRC-II process located in a remote western coal region will include the following operations:

- coal receiving and handling facilities
- liquefaction plant
- gasification unit
- product handling and storage
- auxiliary facilities
    - utilities
    - cooling water
    - oxygen plant
    - sulfur recovery
    - waste handling
    - personnel facilities

Air, water, and solid waste outputs are discussed in Sections a, b, and c respectively. Sludges, slurries, and spent reagents are included in the solid waste section. Noise emissions are discussed in Section d, and odor emissions are discussed in Section e. Section f reviews the general occupational health and safety aspects of coal liquefaction facilities. And, Section g reviews the carcinogenic nature of coal derived liquids and its potential impact on the environment.

TABLE 3-116. COAL ANALYSIS FROM THE POWDER RIVER COAL FIELD; CAMPBELL COUNTY, WYOMING

Component	Concentration Range (wt %)
Proximate Analysis	
Moisture	30.8 - 33.2
Volatile	39.0 - 47.7
Fixed C	31.8 - 52.7
Ash	5.0 - 8.9
Ultimate Analysis	
Ash	5.0 - 8.9
Sulfur	0.3 - 0.8
Hydrogen	4.7 - 5.2
Carbon	45.7 - 74.5
Nitrogen	0.6 - 1.1
Oxygen	16.1 - 40.5

Source: Ctvrtnicek, T.E., S.J. Rusek, and C.W. Sandy. Evaluation of Low-Sulfur Western Coal Characteristics, Utilization, and Combustion Experience. Dayton, Ohio: Monsanto Research Corporation, May 1975.

3.8.2.3a Air Emissions

Air emissions from the SRC-II liquefaction process are primarily attributable to the following processes and operations.

- coal yard operations
- coal drying and grinding
- fuel combustion
- sulfur recovery
- product storage
- fugitive leaks and spills

Although there are other sources of air emissions from a complex coal liquefaction facility, they are not well defined and are generally considered small with respect to the major emission sources which are described here. Air emissions and stack parameters for the major SRC-II emission sources are presented in Table 3-117. Explanations of these air emission sources and references for the emission data are presented below.

Coal Yard Operations

Almost all phases of coal yard operations generate fugitive dust emissions. Coal yard operations at a coal liquefaction facility will include such activities as coal receiving, conveying to storage piles, storage pile maintenance, and conveying from storage piles to the coal drying and pulverizing operations. Based on EPA emissions data for aggregate storage pile operation,

TABLE 3-117. AIR EMISSIONS FROM A 30,000 TPD SRC-II COAL LIQUEFACTION PLANT

	Emission Rate (lbs/hr)							Stack Parameters					
Source	Part	SO_2	Total Organics	CO	NO_x	NH_3	CO_2	Mass Flow 10^3 lb/hr	Vol. Flow 10^3 acfm	Velocity fps	Height ft	Temp. °F	Diameter ft
1. Coal Yard	162	-	-	-	-	-	-	-	-	-	ground level	-	-
2. Drying and Grinding	200	-	-	-	-	-	-	200	(a)	(a)	(a)	(a)	(a)
3. Dissolver Heater													
a	18	34	4	20	207	-	139,000	2200	450	60	200	450	13
b	18	34	4	20	207	-	139,000	2200	450	60	200	450	13
c	18	34	4	20	207	-	139,000	2200	450	60	200	450	13
4. Distillation Heater													
a	3	5	1	3	30	-	20,000	310	65	60	200	450	5
b	3	5	1	3	30	-	20,000	310	65	60	200	450	5
5. Gasifier													
O_2 preheater	0.4	0.7	0.1	0.4	4	-	3,000	50	10	60	200	450	1.9
Steam superheat	0.3	0.6	0.1	0.4	4	-	3,000	40	8	60	200	450	1.7
Char heater	0.6	1.0	0.1	0.6	6	-	4,000	60	13	60	200	450	2.1
Char heater	0.5	0.9	0.1	0.5	5	-	4,000	60	12	60	200	450	2.1
6. Shift Conversion													
Boiler 1	2	4	0.4	3	27	-	18,000	280	58	60	200	450	5
Boiler 2	2	3	0.4	2	21	-	14,000	220	45	60	200	450	4
Shift heater	1	2	0.2	1	12	-	8,000	120	25	60	200	450	3
7. Sulfur Recovery													
a	2	23	0.3	2	20	-	13,000	210	43	60	200	200	4
b	2	23	0.3	2	20	-	13,000	210	43	60	200	200	4
8. Steam Generation													
a	14	26	3	16	160	-	107,000	1700	350	60	200	450	11
b	14	26	3	16	160	-	107,000	1700	350	60	200	450	11
c	14	26	3	16	160	-	107,000	1700	350	60	200	450	11
9. Storage													
Ammonia						12					50		
Light oil			13								50		
Fuel oil			9								50		
10. Fugitive			1020								5		

a. These emissions are vented with the dissolver heater emissions.

emissions for a storage pile in Gillette, Wyoming, would be approximately 1.3 pounds per ton stored.[1] A 30,000 tpd coal liquefaction facility would consequently have an uncontrolled coal yard dust emission rate of 1625 pounds per hour. Concerted dust control efforts can reduce these emissions by as much as 90 percent. Resulting controlled emissions are estimated to be 162 pounds per hour. These emissions are released at ground level.

Coal Drying and Grinding

The raw coal is dried and pulverized in wind swept mills to about 3% moisture. Flue gas from the coal dissolver heaters are used as the drying medium because they represent a readily available source of low temperature heat. Although combustion emissions are present in the drying and grinding vent gases, these are attributable to the dissolver heater and discussed in the next section. Coal drying temperatures are maintained low enough that coal devolatilization does not occur.[2]

A particulate emission factor for fluidized bed coal dryers of 20 lb/ton coal is used to determine the particulate emission rate.[3] According to a study by Hittman Associates Inc., coal drying emissions can be reduced approximately 99.2% by the combined use of cyclones and bag filters.[1] Resulting particulate emissions are 200 lbs/hr.

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[1] U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. EPA Publication No. AP-42. Research Triangle Park, North Carolina: U.S. Government Printing Office, April 1977, p. 11.2.

[2] Jahnig, C. E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process, Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company, March 1975, p. 12.

[3] U.S. Environmental Protection Agency, *op.cit.*, p. 8.9.

Fuel Combustion

Low heating value fuel gas produced by the SRC-II coal liquefaction process is used to supply the process heat demand. Table 3-118 lists expected fuel gas requirements for a 30,000 tpd SRC-II facility based on data from Ralph M. Parsons Company's conceptual design of a 10,000 tpd SRC plant.[2] Steam generation capacity has been increased and electric power generation eliminated from the Parson's design since latest plans by Gulf Mineral Resources Co. are to construct a SRC-II facility that uses steam drives where ever possible and purchases the remaining electrical needs (41 MW).[3]

Combustion characteristics used to calculate air emissions from the fuel combustion sources are presented in Table 3-119. Sulfur oxide emission rates were calculated using the refinery emission standard of 0.10 gr H_2S/dry scf of fuel gas. Nitrogen oxide emissions were assumed controlled to 0.2 lbs/10^6 Btu using staged firing.[4] Particulate, CO, and hydrocarbon emission

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[1] Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report Vol. I, 1974; Vol II, 1975. Colombia, Md.: Hittman Associates, Inc., 1974 and 1975, p. VII-10.

[2] Jahnig, C. E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process, Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company, March 1975, p. 25.

[3] Huffman, Everett L. "Operations at the Wilsonville SRC Plant", presented at the Third Annual International Conference on Coal Gasification and Liquefaction. Pittsburgh, Pennsylvania: University of Pittsburgh, August 1976, p. 11.

[4] Jahnig, C. E., *op.cit.*, p. 12.

TABLE 3-118. SRC-II PLANT FUEL GAS REQUIREMENTS (30,000 tpd)

Unit	Fuel Requirements 10^6 Btu/hr
Coal dissolver heaters	3100
Coal liquefaction product distillation	300
Gasification	100
Shift conversion	300
Sulfur plant	200
Steam generation	2400

Source: Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process. Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey. Exxon Research and Engineering Company. March 1975. p. 65.

TABLE 3-119. SRC-II PLANT FUEL GAS COMBUSTION CHARACTERISTICS

Particulates[a]	15 lb/10^6 scf
Sulfur Oxides[b]	28 lb/10^6 scf
Carbon Monoxide[a]	17 lb/10^6 scf
Hydrocarbons[a]	3 lb/10^6 scf
Nitrogen Oxides[c]	172 lb/10^6 scf
Heating Value[d]	860 Btu/scf
Flue Gas Volume[d]	13 scf/scf

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[a] Source: U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. EPA Publication No. AP-42. Research Triangle Park, North Carolina. U.S. Government Printing Office. April 1977. p. 1.4.

[b] Assumes 0.1 gr/dry scf

[c] Source: Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process. Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey. Exxon Research and Engineering Company. March 1975. p. 12.

[d] Source: Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use. Final Report Vol I, 1974; Vol II, 1975. Columbia, MD. Hittman Associates, Inc. 1974 and 1975. p. VII-10.

factors were developed by EPA.[1] The heating value of plant fuel gas was estimated by Hittman Associates to be 860 Btu/scf, which results in a flue gas volume of 13 scf/scf when combusted with 20% excess air. Stack velocities of 60 ft/sec, heights of 200 ft, and temperatures of 450°F were assumed for dispersion modeling.

Sulfur Recovery

Hydrogen sulfide generated in the coal dissolution and hydrogenation process is recovered as elemental sulfur in the sulfur recovery plant. Due to inefficiencies in the sulfur recovery process, some H_2S remains in the tail gas vented from the sulfur recovery plant. Tail gas cleanup processes will reduce tail gas emissions to very low levels. Based on the conceptual design of a 10,000 tpd SRC facility by Ralph M. Parsons, Exxon Research and Engineering estimated that 0.2% of the sulfur in the coal feed exited the SRC facility in the treated tail gas as SO_2.[2] These sulfur oxide emissions are combined with the flue gas emissions from the sulfur recovery plant heaters.

Product Storage

Product and by-product storage capacity is provided on site to function as surge capacity, allowing continued plant operations during transportation interruptions. Storage area ammonia emissions were calculated using the EPA emission factors for ammonia storage and loading operations.[1] It was assumed that 40% of the nitrogen entering with the coal was recovered as ammonia and that 99% emission control was effected by application of a packed tower scrubber.[2]

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[1] U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. EPA Publication No. AP-42. Research Triangle Park, North Carolina: U.S. Government Printing Office, April 1977, p. 1.4.

[2] Jahnig, C. E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process, Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company, March 1975, p. 48.

Emissions from fuel products storage were calculated using EPA emission factors and assuming two weeks storage capacity.[3,4] Product storage capacities are summarized in Table 3-120.

Fugitive Emissions

There are numerous miscellaneous hydrocarbon emission sources throughout a coal liquefaction facility which are very difficult to account for individually. However, these sources collectively are a major contributor to the emissions from a SRC-II plant. Example fugitive emission sources include waste water drains and sumps, pump seals, valves, flanges, equipment leaks, and loading racks. Based on literature data, Radian Corporation determined that miscellaneous hydrocarbon emissions from a petroleum refinery amount to approximately 0.1 weight percent of the refinery's capacity.[1] Fugitive emissions from the SRC-II liquefaction facility were assumed to be the same, and calculated based on the weight of the liquid products.

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[1] U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors. EPA Publication No. AP-42. Research Triangle Park, North Carolina: U.S. Government Printing Office, April 1977, p. 5.2.

[2] Jahnig, C. E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Processes, Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company, March 1975.

[3] U.S. Environmental Protection Agency, *op.cit.*, p. 4.3.

[4] Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report Vol. I, 1974; Vol. II, 1975. Colombia, Md.: Hittman Associates, Inc., 1974 and 1975, p. VII-7.

TABLE 3-120. DESIGN BASIS FOR CALCULATING STORAGE EMISSIONS

Product	Production Rate bpd	Storage Capacity bbl	Tank Type
Light Oil	15,600	218,400	Floating Roof
Fuel Oil	63,500	889,000	Fixed Roof

Trace Elements

Table 3-121 lists many of the trace elements commonly found in U.S. coals. Some of these elements are highly toxic in one form or another. It is likely that most of these elements appear in the products and effluents from the SRC-II process. However very few of these trace elements form compounds volatile enough to be present in the air emissions. The most volatile trace elements are mercury, selenium, arsenic, lead, cadmium, antimony, fluorine, bromine, boron, and zinc.[2] Arsine and metal carbonyls of some of these trace elements are sufficiently volatile to be present in even cool fuel gas streams. Therefore, the flue gas from combustion of plant fuel gas is likely to contain low levels of these trace elements. These low levels can potentially be important if the fuel gas combustion rates are high.

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[1] Radian Corporation. A Program to Investigate Various Factors in Refinery Siting, prepared for The Council on Environmental Quality and The Environmental Protection Agency. Austin, Texas: Radian Corporation, February 1974, p. 195.

[2] Jahnig, C. E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process, Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company, Marcy 1975, p. 52.

TABLE 3-121. TRACE ELEMENT ANALYSIS OF A TYPICAL U.S. COAL

Element	Concentration (ppm of coal)
As	2
B	700
Ba	8,000
Be	5
Co	20
Cr	60
F	20
Ga	30
Hg	0.06
La	70
Mn	300
Mo	80
Nb	20
Ni	30
Sb	13
Sc	20
Se	0.2
Sn	30
Sr	7,000
Te	0.04
Ti	4,000
Tl	<0.2
U	0.5
V	200
Y	30
Yb	3
Zr	150

Source: Burklin, C.E. Characterization of Waste Effluents From A SRC Coal Conversion Process. Prepared for the Energy Research and Development Administration. Austin, Texas. Radian Corporation. 1975. p. 28.

Organic Compounds

Trace quantities of organic compounds, particularly polynuclear hydrocarbons, may also be emitted from miscellaneous fugitive leaks and spills. Table 3-122 and Table 3-123 list several polynuclear and aromatic compounds which have been identified in SRC products. Many of these compounds have been identified or are suspected of being carcinogens, even at extremely low concentrations. Although these compounds are not considered volatile, they may be present in air emissions from coal liquefaction processes in potentially significant concentrations.

3.8.2.3b Water Effluents

Although the SRC process produces water, the SRC plant as a whole is a net consumer of water. Hence, zero wastewater discharge can be achieved by recycling water effluents after treatments such as dephenolization, steam stripping, biological treatment, and thermal sterilization. These treatments are expensive and consume energy, which increases plant cost and reduces thermal efficiency. The practice is economically attractive only in areas where water resources are limited or effluent water pollution standards are extremely restrictive. The 40,000 ton-per-day Fischer-Tropsch plant now under construction in South Africa is designed for zero wastewater discharge.[1]

There are five major water streams from the SRC processes: foul condensates, condensates from gas purification, condensates from the gasifier, condensates from the reformer, and cooling

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[1] National Research Council. Assessment of Technology for the Liquefaction of Coal, Committee on Sociotechnical Systems, National Research Council. Washington, D.C.: National Academy of Sciences, 1977, p. 113.

TABLE 3-122. CHEMICAL COMPOSITION OF SOLVENT FRACTION

Compounds	Composition (wt %)
Aromatics	
Benzenes	6
Naphthalenes	8
Tetralins	30
Acenaphthalenes	3
Hydroacenaphthalenes	5
Phenanthrenes and Anthracenes	1
Hydrophenanthrenes	5
Crysenes, Pyrenes, Fluoranthrenes	<1
Hydrocrysenes	1
Benzopyrenes	<1
Phenols, Resorcinols, Naphtholes	7
Olefins	1
Saturates	29
	98

Source: Given, P. H., *et al.* The Relation of Coal Characteristics to Coal Liquifaction Behavior, prepared for National Science Foundation, NSF/RA/N-74-154. University Park, PA.: Pennsylvania State University, August 1974.

TABLE 3-123. CHEMICAL COMPOSITION OF SOLVENT FRACTION

Compound	Composition (wt %)
Naphthalene	10
2-Methylnaphthalene	8
1-Methylnaphthalene	3
1, 2-Dimethylnaphthalene	9
Acenaphthalene	5
Anthracene and Phenanthrene	17
Carbozole, Fluoranthene, and Pyrene	5
	62

Source: Auburn University. Solvent Refined Coal Studies, prepared by Engineering Experiment Station, Auburn University, for the National Science Foundation NSF/RA/N-74-075: Auburn University, 1974.

tower blowdown. The flow rates of these streams are presented in Table 3-124. Condensates from the reformer are very clean and can be used directly for boiler feed water. Condensates from gas purification and from the gasifier are low in dissolved solids and organics. These waters can be blended with raw water and treated for use as either boiler makeup or cooling tower makeup. Cooling tower blowdown water will have high levels of dissolved solids (1,500 - 10,000 mg/ℓ) but relatively low levels of organics. It has been suggested that cooling tower blowdown will be used for quench and slag slurrying applications.[1]

TABLE 3-124. WASTEWATER FLOWS FROM A 30,000 TPD SRC PLANT

Stream	Flow Rate lb/hr
Foul Condensates	500,000
Gas Purification Condensates	500,000
Gasifier Condensates	300,000
Reformer Condensates	300,000
Cooling Tower Blowdown	900,000

Source: Water Purification Associates. Water Conservation and Pollution Control in Coal Conversion Processes, Final Report for the U.S. Environmental Protection Agency, Contract No. 68-03-2207. Cambridge, Mass.: Water Purification Associates, July 1977, p. 437.

Jahnig, C. E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process, Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company, March 1975, p. 14.

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[1] Water Purification Associates. Water Conservation and Pollution Control in Coal Conversion Processes, Final Report for the U.S. Environmental Protection Agency, Contract No. 68-03-2207. Cambridge, Mass.: Water Purification Associates, July 1977, p. 437.

The foul condensates are the dirtiest of the wastewaters and will present the major wastewater disposal problem. Foul condensates can not be reused nor discarded without extensive treatment. However, current plans for handling foul condensates are not well documented. Analysis of foul condensates from Pittsburgh and Midway's SRC pilot plant are presented in Table 3-125.

Because the foul condensates have generally been in direct contact with the coal liquids, they will also contain many of the trace elements and organic compounds found in the coal liquids. Of the trace elements commonly occuring in coal (Table 3-121), mercury, selenium, arsenic, molybdenum, lead, cadmium, berylium, fluorine, and antimony are most likely to be found in the foul water systems.[1] Table 3-126 lists several polynuclear organic compounds which have also been identified in typical wastewaters from coal conversion processes.[2] Other polynuclear compounds which may be present in the foul condensates are listed in Table 3-122 and Table 3-123.

Another major source of water effluents from the SRC facility will be coal pile runoff water from heavy rains. Example analyses of runoff from power plant coal piles are presented in Table 3-127. These waters are characteristically very acidic and have high levels of dissolved solids.[3] However,

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[1] Jahnig, C. E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process, Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company, March 1975, p. 32.

[2] Webb, Ronald G., et al. Current Practices in GC-MS Analysis of Organics in Water, Final Report for the Environmental Protection Agency R2-73-277, 16020 GHP. Athens, Georgia: Southeast Environmental Research Laboratory, 1973, p. 53.

[3] Burns and Roe, Inc. Steam Electric Power Plants, Development for Effluent Limitation Guidelines and Standards of Performance. New York, New York: Burns and Roe, Inc., 1973.

TABLE 3-125. ANALYSIS OF FOUL PROCESS CONDENSATES FROM PITTSBURG AND MIDWAY SRC PILOT PLANT

Components	Concentration (mg/ℓ)	
	Sample 1	Sample 2
Total Carbon	9,000	8,160
Total Organic Carbon	6,600	7,390
Inorganic Carbon	2,400	770
BOD (5 day)	32,500	
BOD (15 day)	34,500	
BOD (20 day)	>34,500	
COD	43,600	25,000-30,000
Phenol as C_6H_5OH	5,000	12,000
Total Kjeldahl N	8,300	15,000
Total Ammonia as N	7,900	14,000
Cyanide as CN	10	
Total Sulfur as S	10,500	16,200
Ca	0.47	
Mg	0.14	
Si	<0.5	

Source: Water Purification Associates. Water Conservation and Pollution Control in Coal Conversion Processes, Final Report for the U.S. Environmental Protection Agency, Contract No. 68-03-2207. Cambridge, Mass.: Water Purification Associates, July 1977, p. 267.

TABLE 3-126. CONCENTRATIONS OF ORGANIC COMPOUNDS IN COAL CONVERSION PROCESS WASTES

Compound	Concentration mg/ℓ
Acenaphthene	0.2
n-Butylisothiocyanate	0.5
Carbazole	0.3
Cresol	2.5
2,6-Dimethyl naphthalene	0.015
Dimethyl pyridine	0.2
Ethylisothiocyanate	1.5
Fluoranthene	0.6
Fluorene	0.17
Indene	0.026
Methyl naphthalene	0.03
Naphthalene	0.05
Phenanthrene	1.4
Phenol	0.6
Trimethylpyridine	0.3
Xylene	0.008
Xylenol	1.5

Source: Webb, Ronald G., *et al.* Current Practices in GC-MS Analysis of Organics in Water, final report for the Environmental Protection Agency R2-73-277, 1602D GHP. Athena, Georgia. Southeast Environmental Research Laboratory. 1973. p. 53.

TABLE 3-127. WATER QUALITY OF COAL PILE RUNOFF

Coal Pile No.		1	2	3	4	5	6	7	8
BOD	mg/ℓ	0	0	10	-	3	-	-	-
COD	mg/ℓ	1,080	1,080	806	85	1,099	-	-	-
Dissolved Solids	mg/ℓ	720	720	7,743	5,800	247	-	28,970	44,050
Suspended Solids	mg/ℓ	610	610	22	200	3,302	-	100	950
NH^-	mg/ℓ	0	0	1.77	1.35	0.35	-	-	-
$NO^=$	mg/ℓ	0.3	0.3	1.9	1.8	2.25	-	-	-
P	mg/ℓ	-	-	1.2	-	0.23	-	-	-
Turbidity	mg/ℓ	505	505						
Hardness	mg/ℓ	130	130	1,109	1,850	-	-	-	-
$SO^=$	mg/ℓ	525	525	5,231	861	133	6,837	19,000	21,920
Cl^-	mg/ℓ	3.6	3.6	481	-	23	-	-	-
Al	mg/ℓ	-	-	-	-	-	-	1,200	825
Cr	mg/ℓ	0	0	0.37	0.05	-	-	15.7	0.3
Cu	mg/ℓ	1.6	1.6	-	-	-	-	1.8	3.4
Fe	mg/ℓ	0.168	0.168	-	0.06	-	0.368	4,700	93,000
Mg	mg/ℓ	-	-	89	174	-	-	-	-
Zn	mg/ℓ	1.6	1.6	2.43	0.006	0.08	-	12.5	23
Na	mg/ℓ	1,260	1,260	160	-	-	-	-	-
pH		2.8	2.8	3	4.4	7.8	2.7	2.1	2.8

Source: Burns and Roe, Inc. Steam Electric Power Plants, Development for Effluent Limitation Guidelines and Standards of Performance. New York, New York. Burns and Roe Inc. 1973.

runoff from low sulfur western coals is not likely to be as acidic as these examples. Normally, coal pile runoff will be collected in ponds and used by the SRC plant. If clean enough, these waters can be treated and used for plant makeup. Otherwise these waters will be used for dust control on the coal pile and coal roads.[1]

3.8.2.3c Solid Wastes, Sludges, Spent Catalysts

The major source of solid waste from a SRC-II facility is the gasifier ash. A 30,000 tpd coal liquefaction facility will produce approximately 2500 tpd of gasifier ash. The major constituent of this ash will be minerals entering with the coal. Depending on the nature of the gasification process, gasifier ash will also contain various concentrations of trace elements and polynuclear organic compounds. Some of the trace elements and polynuclear organics potentially present are presented in Table 3-121 and Table 3-126, A more in-depth discussion of the characteristics of gasifier ash is presented in Section 3.8.1.3 on Gasifier Outputs.[2]

The method of disposal for gasifier ash will vary with plant design, but will generally be coupled with the coal delivery operation. Many plant designs provide for ash disposal at the coal mining site. On-site landfilling is another alternative.[3]

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[1] Jahnig, C. E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes: SRC Process, Final Report for U.S. Environmental Protection Agency, Contract No. 68-02-0629. Linden, New Jersey: Exxon Research and Engineering Company, March 1975, p. 31.

[2] (Ralph M.) Parsons Company. Demonstration Plant · Clean Boiler Fuels from Coal, Office of Coal Research R&D Report 82, Int. Rpt. 1, 3 Volumes, Contract No. 14-32-0001-1234. Los Angeles, California: Ralph M. Parsons Company, September 1973.

[3] *Ibid.*

Two major sources of sludge from coal liquefaction operations are process water treating and wastewater treating. Common process water treating techniques include filtration, lime/lime-soda softening, and ion exchange. The major constituents of process water treatment sludges include minerals entering with the raw process water, coagulating and flocculating agents, lime, and soda. The most common flocculating agents are alum, aluminates, ferric chloride copperas, bentenites, and polyelectrolytes.[1]

Wastewater treatment sludges consist of oily grit removed by the API separator and biological sludge from the bio-ponds. These sludges consist primarily of coal ash minerals, waste oils, and biological material, but may also contain small quantities of trace elements and polynuclear organics.

The flow rates of these sludges are highly dependent on raw water quality and wastewater handling practices. However, the volume of these sludges is much smaller than the volume of gasifier ash. Disposal of these sludges is normally by the same methods as gasifier ash.[2]

A wide variety of catalysts and sorbents will be used in the SRC-II process. Many of these are listed in Table 3-111. These catalysts and sorbents deactivate with time or during plant upsets. Generally, catalysts must be replaced on a schedule of one or two years, although sorbents may require more frequent replacement. In some cases the catalysts and reagents will be discarded with the gasifier ash and sludge. However, in most cases they will be returned to the supplier for reclamation.[1]

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[1] (Ralph M.) Parsons Company. Demonstration Plant · Clean Boiler Fuels from Coal, Office of Coal Research R&D Report 82, Int. Rpt. 1, 3 Volumes, Contract No. 14-32-0001-1234. Los Angeles, California: Ralph M. Parsons Company, September 1973.

[2] *Ibid.*

3.8.2.3d Noise Pollution

Coal receiving, conveying, and crushing are particularly noisy operations and will require careful shielding design to reduce in-plant noise to the levels required by the Occupational Safety and Health Act (OSHA). The remainder of the coal liquefaction plant is comparable in noise generation to oil refineries and should create no unusual problems.[2]

3.8.2.3e Odor

There will undoubtedly be disagreeable odors associated with any coal liquefaction process. Many malodorous compounds such as mercaptans, hydrogen sulfides, organic nitrogen compounds, phenols, cresols, and naphthenic acids are present in the SRC-II process. These compounds are perceptible at concentrations as low as one part per billion, or even less. As a result, extremely small concentrations, well below toxic or harmful levels, may still present a nuisance to nearby residents. However, good housekeeping practices and other practices which reduce fugitive emissions will aid significantly in the reduction of the odor nuisance.

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[1] Hittman Associates, Inc. Technology and Environmental Overviews: Coal Liquefaction, Draft Final Report, for U.S. Environmental Protection Agency, Contract No. 68-02-2162. Columbia, Maryland: Hittman Associates, 1977.

[2] National Research Council. Assessment of Technology for the Liquefaction of Coal, Committee on Sociotechnical Systems, National Research Council. Washington, D.C.: National Academy of Sciences, 1977, p. 115.

3.8.2.3f Occupational Health and Safety

Available data on the carcinogenicity of products from processes currently under development are limited. Samples of solvent refined coal (SRC), solvent, and heavy hydrogenated SRC prepared from Pittsburgh seam coal at the ERDA Cresap pilot plant in 1970 were tested in cutaneous applications with mice at Kettering Laboratory. As compared to benzo-(a) pyrene, a solution of SRC was weakly carcinogenic, and the hydrogenated bottoms and solvent were moderately carcinogenic.

Hygienic practices and medical surveillance are employed by most organizations now engaged in liquefaction process development. Similar practices are employed on a commercial scale by SASOL, with a reported complete absence of carcinogenic reaction by the workmen. The basic principle involved is the avoidance of prolonged contact with the potentially carcinogenic materials; this requires bathing at the end of a workday, laundering work clothes each day, and inspection to establish the complete removal of carcinogens.[1]

Data on injuries, deaths, and man-days lost are available from Battelle. Converting from Battelle's basis of 10^6 Btu to a 100,000 BPD plant yields the following expected annual values: 0.32 deaths, 6.2 injuries, and 1,494 man-days lost.[2]

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[1] National Research Council. Assessment of Technology for the Liquefaction of Coal, Committee on Sociotechnical Systems, National Research Council. Washington, D.C.: National Academy of Sciences, 1977, p. 116.

[2] Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle Columbus Laboratories, 1973.

3.8.2.3g Community Exposure

Concern has been expressed about the risk to adjacent communities that may arise from coal liquefaction manufacture. Although some hazardous compounds are present in the coal liquefaction process, coal liquefaction plants, like petroleum refineries, are continuous, closed systems. Uncontrolled emissions to the atmosphere will not occur in a well designed commercial plant during normal operation.[1]

The Ad-Hoc Panel on Liquefaction of Coal (National Research Council) appointed to assess coal liquefaction technology reports that based on present knowledge of processes and emissions, they see no reason for the potential exposure of a community to environmental hazards from an adjoining coal liquefaction plant to exceed that from other existing controlled industrial operations.[2]

3.8.2.4 Summary

Table 3-128 presents a summary of the inputs and outputs associated with a 30,000 TPD SRC-II coal liquefaction plant located near Gillette, Wyoming. Although these impacts will vary somewhat from location to location due to the type of coal used, meteorological conditions, etc., they are not expected to vary significantly between various sites in the Western States.

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[1] National Research Council. Assessment of Technology for the Liquefaction of Coal, Committee on Sociotechnical Systems, National Research Council. Washington, D.C.: National Academy of Sciences, 1977, p. 116.

[2] *Ibid.*

TABLE 3-128. SUMMARY OF IMPACTS ASSOCIATED WITH A 30,000 TPD SRC-II COAL LIQUEFACTION PLANT AT GILLETTE, WYOMING

Input Requirements	
Manpower	
• construction	21,900 man-years
• operating	1,600 men
Materials and Equipment	
• fabricated steel	200,000 tons
• concrete	288,000 tons
• refined products	50,000 tons
Operating Reagents	40 tons/day
Economics	
• capital costs	\$1.2 – \$1.3 billion[a]
• operating costs (excluding coal costs	\$219 million/year
Water	
• @ 100% reuse and recycle	4 million gal/day
• @ current development plans	17 million gal/day
Land	1800 acres
Ancillary Energy	41 MW
Outputs	
Air Emissions	
• particulates	475 lb/hr
• SO_2	248 lb/hr
• total organics	1,067 lb/hr
• CO	126 lb/hr
• NO_x	1,280 lb/hr
• NH_3	12 lb/hr
• CO_2	858,000 lb/hr
Water Effluents	negligible
Solid Wastes	2,500 ton/day
Noise	negligible
Odor	trace
Occupational Health and Safety	
• fatalities	0.32 deaths/yr
• injuries	6.2 injuries/yr
• man-days lost	1494 man-days/yr

[a] 1976 dollars

3.8.3 Electrical Generation

The electrical generation facilities considered here are designed to produce electricity by the direct combustion of coal in boilers. The unifying characteristic of boiler-fired power plants is that the electrical energy is generated by a series of three conversion stages. First, the chemical energy of the coal is converted to heat energy by combustion in the boiler. This heat is transferred to some working fluid, usually water and/or steam. Second, the heat energy of the working fluid is converted to mechanical energy by a turbine (or heat engine in thermodynamic terminology). Third, the mechanical energy is converted to electrical energy by a generator.

In the boiler, coal is combusted, generating combustion by-products and heat. The combustion by-products are removed from the boiler as ash and stack gases. Pollutants in the stack gases may be removed by a stack gas cleaning mechanism before the gases are released to the atmosphere. The heat produced by the combustion is transferred to water to produce high-pressure, high-temperature steam. The steam enters the turbine where it expands to a low pressure and low temperature and drives the turbine which in turn drives the generator.

After the thermal energy in the steam has been converted to mechanical energy, the discharged steam is condensed to water. The water is then pumped back into the boiler to start the cycle over again. The heat removed in the condenser is rejected into bodies of water (i.e., lakes, ponds, rivers, etc.) or to the atmosphere by cooling towers. A simplified schematic of this type of power plant is shown in Figure 3-28.

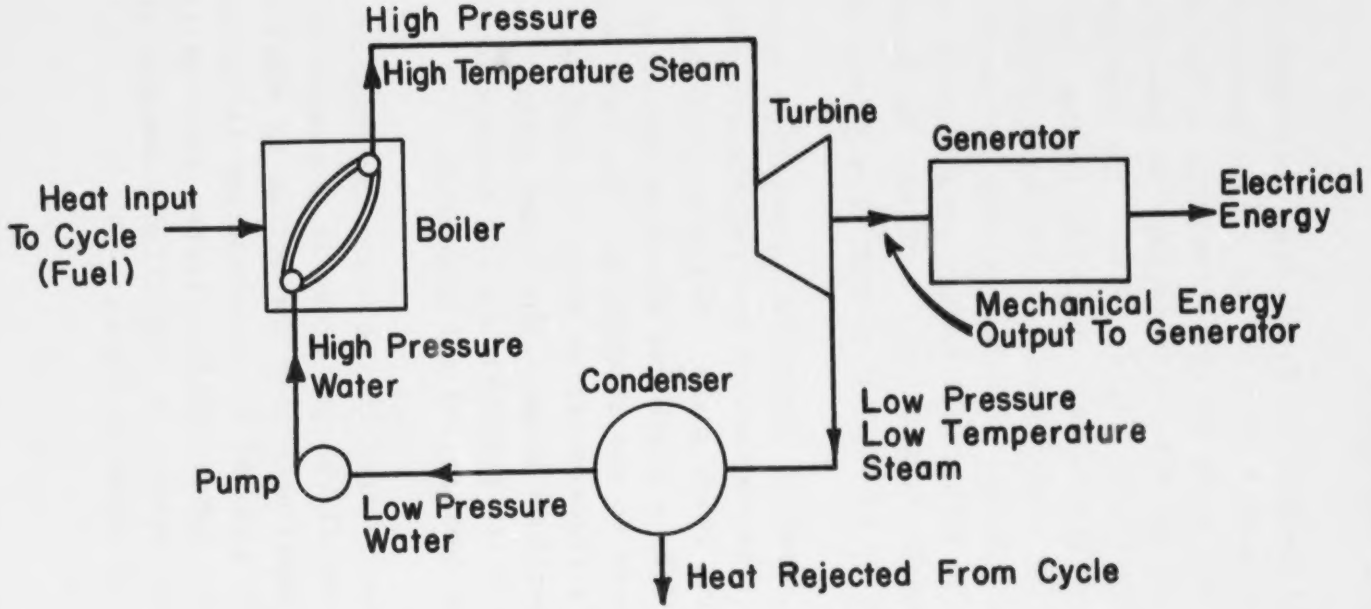
High Pressure
High Temperature Steam
Turbine
Generator
Electrical Energy
Heat Input To Cycle (Fuel)
Boiler
Mechanical Energy Output To Generator
High Pressure Water
Condenser
Low Pressure Low Temperature Steam
Pump
Low Pressure Water
Heat Rejected From Cycle

Figure 3-28. Simplified Schematic of a Steam Power Plant.

Source: U.S. Atomic Energy Commission. Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program, 4 Vols. Washington, D.C.: Government Printing Office, 1974.

3.8.3.1 Technology Description

The technological description of this electrical generation section is divided into the following segments: boilers, turbines, generators, stack gas cleaning, and cooling.

Boilers

Boilers are mechanisms that burn fuel to create heat energy which is then transferred to a fluid (normally water) to produce steam. To improve thermal efficiencies, both conventional boilers and the new fluidized bed combustors generally contain other system components such as:[1]

1. Superheaters. A superheat is a system of tubes located at the top of the boiler in which the saturated steam is superheated by combustion gases.

2. Reheaters. A system of tubes much like the superheater, the reheater reheats partially expanded steam taken from the early stages of the turbine. The steam is then returned to the final stages of the turbine.

3. Economizers. An economizer extracts heat from the flue gases (after the superheater) and transfers it to the boiler feedwater.

4. Air preheaters. An air preheater extracts additional heat from the flue gases (after the economizer) and transfers it to the combustion air before it is fed into the furnace.

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[1] University of Oklahoma, Science and Public Policy Program. Energy Alternatives: A comparative Analysis. Washington, D.C.: Government Printing Office, 1975.

In addition to these components, the boiler also has steam separators, fans, pumps, fuel handling equipment, and combustion by-product handling equipment.

Because combustion occurs in the boiler, it produces most of the potentially adverse environmental residuals associated with electric power generation.[1]

Conventional boilers are extremely large and complex. Some steam power plant boilers are 10 or more stories tall. Figure 3-29 is a simplified boiler design showing the air and flue gas circulation patterns.

A number of variables affect conventional boiler design, a primary one being the type of fuel to be burned. Coal is generally pulverized to a very fine powder (approximately 200 mesh) and then blown into the furnace. However, additional problems that must be dealt with when coal is burned include fly ash handling and slagging.

The firing mechanism and techniques are other important conventional boiler design variables that affect the combustion pattern and temperature control. In some cases the burners are directed vertically downward, an option used primarily with solid fuels. In others, the burners are fired horizontally, in opposition, or tangentially along the walls of the furnace. In a frequently used technique, staged firing, 90 to 95 percent of the air enters the boiler as primary and secondary air with the fuel before combustion, and the remainder enters as tertiary air through auxiliary ports in the furnace. Because of imperfect

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[1] University of Oklahoma, Science and Public Policy Program. Energy Alternatives: A Comparative Analysis. Washington, D. C.: Government Printing Office, 1975.

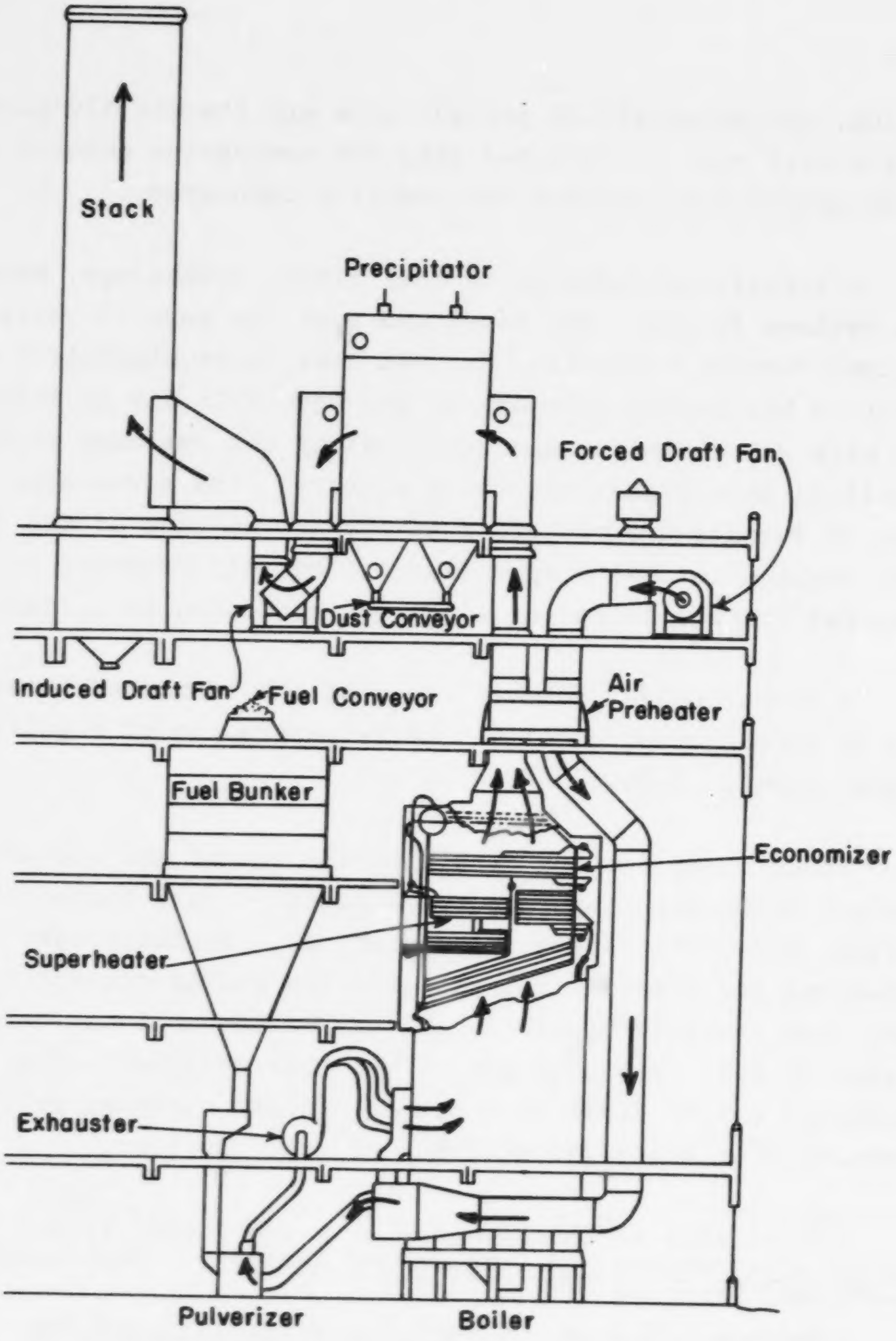
Stack
Precipitator
Forced Draft Fan
Dust Conveyor
Induced Draft Fan
Fuel Conveyor
Air Preheater
Fuel Bunker
Economizer
Superheater
Exhauster
Pulverizer
Boiler

Figure 3-29. Boiler Air and Flue Gas Circulation Patterns

Source: Shields, C. D. Boilers, Types, Characteristics, and Functions. New York: McGraw-Hill, 1961 mixing, approximately 20 percent more air (termed 120-percent excess air) must be injected into the combustion chamber than is theoretically required for complete combustion.[1]

A significant advance in coal firing technology, known as the cyclone furnace, has developed over the past 35 years. In cyclone furnace operation, crushed coal (approximately 4 mesh) enters a horizontal cylinder at one end while air is injected (at high velocities) tangentially along the cylinder periphery, resulting in a cyclonic burning pattern. The advantages of this type of furnace are reduction in fly ash content of the flue gas, savings in fuel preparation (since only crushing is required instead of pulverizing) and reduction in furnace size.[2]

A disadvantage, however, is that the increased temperatures due to accelerated combustion cause generation of significantly higher levels of NO_x.[3]

Three major factors determine the amount and character of the air pollutants generated by a boiler: fuel burned, boiler design, and boiler operating conditions. Sulfur oxides (SO_x) emissions are directly relatable to the sulfur content of the fuel, and there is little in the way of conventional boiler design or operation that can affect this residual. These SO_x emissions can be dealt with either by coal cleaning prior to combustion or stack gas cleaning after combustion.

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[1] University of Oklahoma, Science and Public Policy Program. Energy Alternatives: A Comparative Analysis. Washington, D.C.: Government Printing Office, 1975.

[2] Babcock & Wilcox. Steam/ Its Generation and Use, 38th Ed. New York: Babcock & Wilcox, 1972.

[3] National Research Council, Commission on Sociotechnical Systems. Assessment of Advanced Technology for Direct Combustion of Coal. Prepared for: National Academy of Sciences, Washington, D.C. 1977.

Nitrogen oxides (NO_x) emissions can be significantly affected by boiler design and operating conditions, but the process of NO_x formation during combustion is not completely understood. The major factor affecting the formation of NO_x is temperature. One study indicates that the most important variables for fossil-fueled boilers in controlling NO_x emissions are staged firing, low excess air (less than 110 percent of the actual requirement for complete combustion), and flue gas recirculation.[1] This study indicated the potential for similar methods to be applied for coal, but the emission of NO_x from coal-fired boilers is the least explored and the most difficult problem area of all the NO_x emission sources.[2]

Particulate emissions are a major problem with coal-fired boilers. Improved boiler design can reduce these emissions. The primary advance in this area is the cyclone furnace described earlier, which can reduce fly ash by 50 percent over pulverized units, but with a significant increase in NO_x emissions. The particulates generated in a coal-fired boiler primarily consist of ash in the coal which becomes entrained in the flue gases (fly ash). The major factor affecting these emissions, therefore, is the amount of ash contained in the coal. The primary method of controlling particulates is stack gas cleaning, which will be discussed subsequently.

In addition to the pulverized and cyclone furnaces discussed above, a third type of boiler currently being analyzed is the fluidized bed boiler. The desire to reduce pollutants as well as to improve boiler efficiency has led to increased work on fluidized bed boilers. Such boilers are not commercially available at present, but their proponents believe they hold great promise as substitutes for conventional steam boilers.

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[1] Bartok, W., A. R. Crawford, and G. J. Piegari. "Systematic Investigation of Nitrogen Oxide Emissions and Combustion Control Methods for Power Plant Boilers", in Air Pollution and Its Control, AIChE Symposium Series 68 (125), A. F. Sarofim and N. J. Weinstein, eds. New York, American Institute of Chemical Engineers, 1972.

[2] *Ibid.*

In a fluidized bed boiler air is passed upward through a grid plate supporting a thick (several feet) bed of granular, noncombustible material such as coal ash or lime. The air fluidizes the granular particulates and, with the relatively small amount of air used to inject the fuel serves as the combustion air. The heat transfer surfaces or boiler tubes can be embedded directly in the fluidized bed because combustion takes place at temperatures (approximately 1,500°F) that will not damage the tubes.

The fluidized bed boiler has two basic advantages: the ability to burn high-sulfur coal with low sulfur dioxide (SO_2), particulate, and, to some extent, NO_x emissions; and high heat release and heat transfer coefficients that can drastically reduce boiler size, weight, and cost. This means that fluidized bed boilers can be built as factory-assembled, packaged units, shipped to sites, and arrayed as required. These factors would considerably reduce construction times for new power plants.[1]

There are several fluidized bed concepts at various stages of development. In this section one of the processes treated in the Hittman study[2] will be described: the Pope, Evans, and Robbins Atmospheric Pressure Fluidized Bed Boiler.

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[1] Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc., 1974 and 1975.

[2] *Ibid.*

The Pope, Evans, and Robbins Atmospheric Pressure Fluidized Bed Boiler, being developed for the Office of Coal Research (OCR), is designed as a replacement for conventional boilers. This system is illustrated in Figure 3-30. The system uses repeating elements or cells to make any size boiler desired, thus reducing scale-up problems. The largest fluidized bed boiler currently in use is the four cell 30-MW unit at Riversville, West Virginia which is expected to provide many answers regarding large scale application of thise boilers.[1]

Turbines

The purpose of the turbines at a power plant is to convert the heat energy released in the boiler to mechanical energy for turning generators. The turbines discussed in this section are steam turbines utilizing high-temperature, high-pressure steam generated by coal combustion.

In these steam turbines, the high-temperature, high-pressure steam is allowed to expand greatly increasing its velocity but decreasing temperature and pressure. The high velocity steam impacts turbine blades causing rotation. Depending on the turbine design, the steam turbine can have one or several stages to extract energy from the high-temperature, high-pressure steam and produce a low-pressure, low-temperature steam.

The typical operating conditions for a steam turbine are an input steam temperature of about 1000°F and an outlet temperature of about 100°F. The mechanical efficiency (percent thermal energy removed from the steam which is converted to usable

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[1] National Research Council, Commission on Sociotechnical Systems. Assessment of Advanced Technology for Direct Combustion of Coal. Prepared for: National Academy of Sciences, Washington, D.C. 1977.

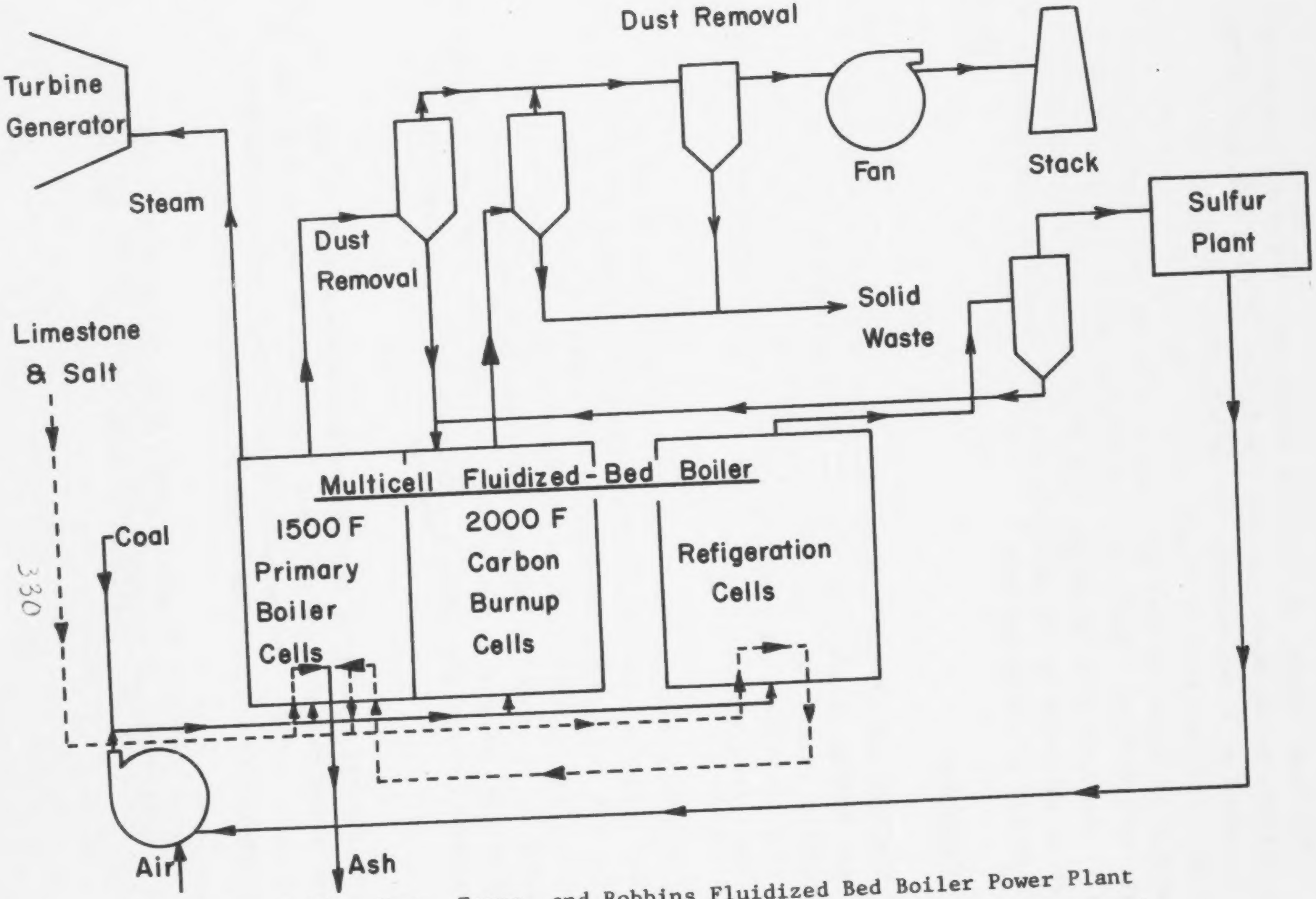
Dust Removal
Turbine Generator
Steam
Dust Removal
Fan
Stack
Sulfur Plant
Solid Waste
Limestone & Salt
Coal
Multicell Fluidized-Bed Boiler
1500 F Primary Boiler Cells
2000 F Carbon Burnup Cells
Refigeration Cells
Air
Ash

Figure 3-30. Pope, Evans, and Robbins Fluidized Bed Boiler Power Plant

Source: Hittman Associates, Inc. Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Final Report: Vol. I, 1974; Vol. II, 1975. Columbia, Md.: Hittman Associates, Inc., 1974 and 1975.

mechanical energy) is less than 60%. Although this efficiency cannot be significantly improved by turbine design, the quantity of heat available for conversion can be increased by various methods. One such method is the use of reheaters. In this design, steam is removed from the turbine between the high and low-pressure stages and heated with boiler flue gases. Although this will not significantly affect turbine mechanical efficiency, it will increase overall plant efficiency by utilizing more available heat.

Another method of increasing overall plant efficiency is the binary cycle design. In this design, two or more heat engine cycles covering different parts of the temperature range are combined. When the second cycle is added to the high-temperature end, it is referred to as a topping cycle; a second cycle added to the low-temperature end is termed a bottoming or tailing cycle.

The binary cycle which has been the subject of much research and development is the liquid metal combined cycle design. In this design, a metal which will be a liquid at boiler feed temperatures (*e.g.*, mercury or potassium) is used as the working fluid in the boiler. The principal advantage of using one of the liquid metals as the working fluid is their high boiling or vaporizing temperatures at relatively low pressures. While water boils at 662°F at 2,400 pounds per square inch absolute (psia), mercury boils at 907°F at 100 psia and potassium boils at 1,400°F at 14.7 psia (one atmosphere). By vaporizing these metals in the boiler, therefore, a much higher temperature at the input to the topping turbine is possible. Even after the high-temperature vaporized metal has been through the topping turbine, it contains enough heat to produce steam while being condensed. This steam is then used in the steam turbine. By utilizing these two turbines (combined cycle) a greater temperature range can be achieved. Although the efficiency of the liquid-metal Rankine cycle by itself is not high, by using the condenser for the liquid metal as the boiler for the water, the overall efficiency is relatively high.[1] For example, the overall efficiency of a conventional steam cycle power plant is about 28%. The binary cycles, however, can achieve efficiencies of approximately 50%.

Between 1922 and 1950, the General Electric Company constructed a series of six fossil-fueled mercury and steam binary cycle power plants. These mercury plants demonstrated the practical feasibility of the mercury topping cycle. However, no mercury topping cycles were built after 1950. This is due to the improved efficiency and economics of scale of the modern conventional steam power plants and the high costs associated with construction and operation of the binary cycle.

Generators

The mechanical energy from the turbine is converted to electrical energy by the generator. An electrical generator relies on the basic phenomenon in electromagnetics; when an electrical conductor is moved properly through a magnetic field, a voltage will develop along the conductor. The only type of alternating current (AC) generator presently used in large power plants is the synchronous type, whereby the speed of the rotor is related to the frequency of the current produced. In the large synchronous generators, the conductor is stationary while the magnetic field is rotated. The efficiency of these generators (*i.e.*, the percent of the input mechanical energy which is converted to usable electrical energy output) is about 95 percent.

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[1] U.S. Atomic Energy Commission. Draft Environmental Statement: Liquid Metal Fast Breeder Reactor Program, 4 Vols. Washington, D.C.: Government Printing Office, 1974.

Stack Gas Cleaning

Stack gas cleaning is the process by which contaminants are removed from the boiler flue gases before the gases are vented to the atmosphere. Some stack gas cleaning processes, such as those for collecting sulfur dioxides and particulates, are commercially available at present. Other processes for the removal of nitrogen oxides are still a developing technology. The systems which are available for stack gas cleaning depend on the contaminant to be removed. The following sections describe technologies for removal of particulates, nitrogen oxides and sulfur dioxide.

Particulates

Removing particulates from the gases can be accomplished mechanically, electrostatically, or as part of the SO_2 removal. Mechanical separation takes place in a cyclone where the flue gases are rotated at high speed to throw the higher-mass particulates against the outside walls where they are separated. The dust may be collected using water (irrigated cyclone) or simply allowed to fall into a hopper (dry cyclone). Depending on size and type, mechanical separators vary in efficiency from 65 to 94 percent.[1]

Electrostatic precipitators impose a very high electric field on a series of wires and tubes (or wires and plates) so that a low-current electric discharge occurs between them. If the particulates to be removed can be ionized, they will respond to this field and be drawn to the tubes. Waste disposal is usually accomplished by rapping the tubes and collecting the dust. The performance of a precipitator depends strongly on the percent sulfur in the coal which is combusted. This is because the electrical resistivity of the fly ash is high. For example, if a unit is designed for 95-percent efficiency using 5-percent sulfur coal, it will operate at only 70-percent efficiency with 0.59-percent sulfur coal. This poses special problems with combustion of low-sulfur western coals.[2]

In addition, the efficiency of electrostatic precipitators is highly dependent on the stack gas temperature. A system giving 92-percent efficiency at 310°F may only give 55-percent efficiency at 270°F.[3] This presents a problem for startup, since there is significantly lower particulate removal until the precipitator temperature is brought up to design temperature. Most electrostatic precipitators are designed to have removal efficiencies of between 92 and 99 percent.

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[1] Nonhebel, G., ed. Gas Purification Processes. London: George Newnes Limited, 1964.

[2] National Research Council, Commission on Sociotechnical Systems. Assessment of Advanced Technology for Direct Combustion of Coal. Prepared for: National Academy of Sciences, Washington, D.C. 1977.

[3] Soo, S. L. "A Critical Review on Electrostatic Precipitators", pp. 185-193 in R. W. Coughlin, A. F. Sarofim, and N. J. Weinstein, eds. Air Pollution and Its Control, AIChE Symposium Series, Vol. 68, No. 126. New York: American Institute of Chemical Engineers, 1972.

Another particulate control device which is being proposed for use with pulverized-coal-fired boilers is the bag filter.[1] These devices utilize cloth filters which collect particulates as the flue gases are forced through the fabric. The collected particulates are collected by shaking the filters and allowing the particulates to fall. The efficiencies of these devices are generally over 99 percent.

Sulfur Dioxide

Sulfur dioxide (SO_2) residuals have been a major air pollution concern associated with electric power generation and the most difficult to control. Although more than 50 individual flue gas desulfurization processes (FGD) have been identified[2], the most effective appear to be "scrubbing" processes in which the stack gas is intimately contacted with a material that reacts with SO_2 to form a compound. The resultant compound is then either dumped (nonregenerable methods) or treated so that some useful form of the sulfur may be recovered.

The nonregenerable methods convert an air pollution problem to a solid waste problem, while the recovery methods involve costly production of a by-product such as elemental sulfur or gypsum. The commercial value of these by-products from a regenerable FGD system are generally uncertain and depend on many economic factors which will not be considered here. In addition, many utility companies may be hesitant to get into what is viewed as the chemical business.

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[1] National Research Council, Commission on Sociotechnical Systems. Assessment of Advanced Technology for Direct Combustion of Coal. Prepared for: National Academy of Sciences, Washington, D.C. 1977.

[2] Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle Columbus Laboratories, 1973.

Lime and/or limestone nonregenerable processes are currently favored by the electric utility industry as the best solution to SO_2 emissions.[1] As of June 1977, 97% of the new generating capacity constructed with flue gas desulfurization (FGD) systems and 83% of the retrofit capacity with FGD systems used lime and/or limestone scrubbing.[2] The three basic forms of this system are shown in Figure 3-31. In each system, SO_2 is reacted with lime and/or limestone to form calcium sulfate and calcium sulfite which is disposed of in settling ponds. A description of the three basic alternatives shown in Figure 3-31 is as follows:

1. Introduction of limestone directly into the scrubber. This is the simplest route and seems to be the one favored by the power industry at present. The main drawback is that limestone is not as reactive as lime, which makes it necessary to use more limestone, install a larger scrubber, recirculate more slurry, grind the limestone finer, and otherwise offset the lower reactivity.

2. Introduction of lime into the scrubber. Scrubbing efficiency can be improved by first calcining the limestone to lime (CaO) and introducing the lime into the scrubber. However, the cost is increased greatly over that for limestone slurry scrubbing, since a

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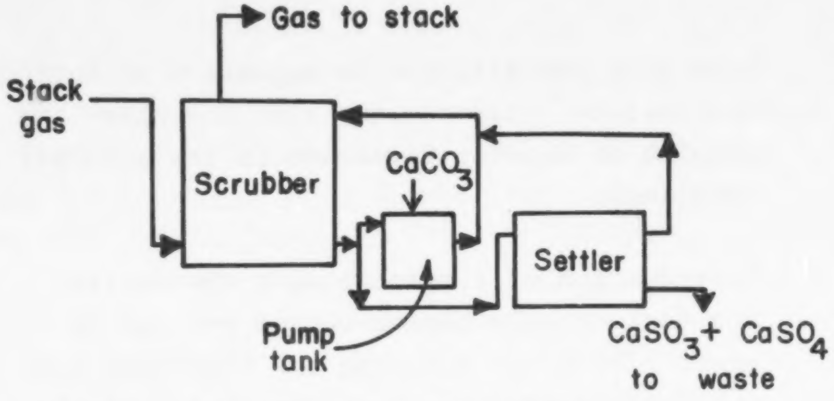
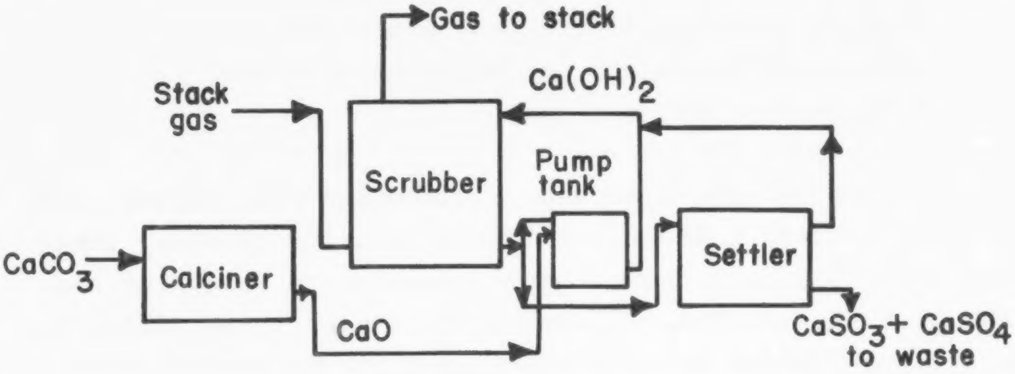
[1] Slack, A. V., H. L. Falkenberry, and R. E. Harrington. "Sulfur Oxide Removal from Waste Gases: Lime-Limestone Scrubbing Technology."

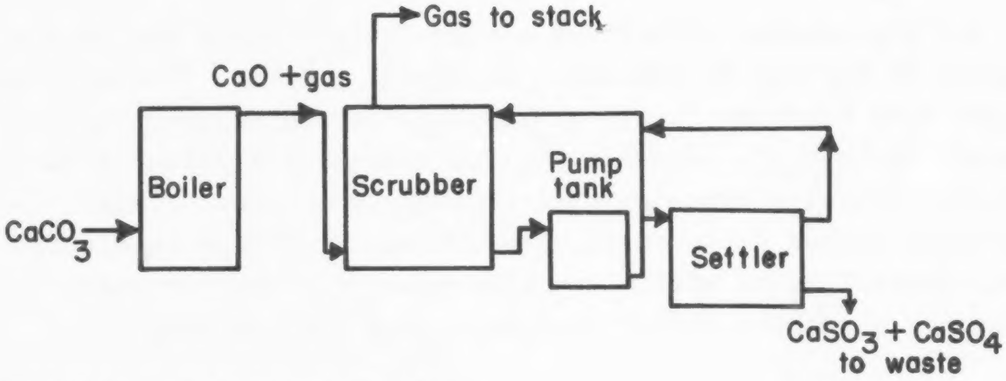
[2] PEDCo Environmental Specialists, Inc. Summary Report, Status of Flue Gas Desulfurization Systems in the U.S., April-May 1977. Cinncinatti, OH: 1977.


Gas to stack
Stack gas
Scrubber
$CaCO_3$
Settler
Pump tank
$CaSO_3$ + $CaSO_4$ to waste

METHOD I. SCRUBBER ADDITION OF LIMESTONE


Gas to stack
Stack gas
$Ca(OH)_2$
Scrubber
Pump tank
$CaCO_3$
Calciner
Settler
CaO
$CaSO_3$ + $CaSO_4$ to waste

METHOD 2. SCRUBBER ADDITION OF LIME


Gas to stack
CaO +gas
Boiler
Scrubber
Pump tank
$CaCO_3$
Settler
$CaSO_3$ + $CaSO_4$ to waste

METHOD 3. BOILER INJECTION

Figure 3-31. Lime and Limestone Stack Gas Scrubbing Methods

Source: Slack, A.V., H. L. Falkenberry & R. E. Harrington. "Sulfur Oxide Removal from Waste Gases: Lime-Limestone Scrubbing Technology", J. APCA 22 (3), 159 (1972).

lime kiln installation is expensive to build and operate. Use of lime also increases the problem of deposit formation in the scrubber (scaling).

3. Introduction of limestone into the boiler. The cost of calcination can be reduced in power plants by injecting the limestone into a boiler furnace. The gas then carries the lime into the scrubber. Problems include possibility of boiler fouling, danger of overburning and inactivating the lime, and increased scaling in the scrubber when the lime enters with the gas.

In addition to the lime and/or limestone FGD systems, the three other systems currently in use or soon to be operational are magnesium oxide scrubbing, sodium carbonate scrubbing and Wellman Lord/Allied Chemical scrubbing. The primary difference between these systems and the lime/limestone systems is that the SO_2 stream can then be utilized to form elemental sulfur, H_2SO_4 or other by-products.

The SO_2 removal efficiency of the FGD processes are generally designed to be over 90 percent. In actual practice, however, some systems have achieved significantly lower efficiencies. In addition to this SO_2 removal, the FGD systems all effect a particulate removal efficiency greater than 99 percent. This removal is either achieved in the scrubber itself or in electrostatic precipitators within the FGD system for the purpose of protecting scrubbers and/or absorbers from particulates.

A listing of the electrical generating capacity which utilizes each type of FGD system currently or soon to be in use as of June 1977 is shown in Table 3-129. Table 3-130 shows a breakdown of the generating capacity for which FGD systems are already operational, are under construction, or are planned. In addition, it should be noted that there are many other types of FGD systems under consideration for future use.

TABLE 3-129. GENERATING CAPACITY UTILIZING FGD SYSTEMS
JUNE 1977

FGD System	MW
Lime Scrubbing	2702
Lime/Alkaline Scrubbing	720
Lime/Limestone Scrubbing	20
Limestone Scrubbing	3767
Magnesium Oxide Scrubbing	120
Sodium Carbonate Scrubbing	375
Wellman Lord/Allied Chemical[1]	455
Total	8159

[1] 350 MW of this capacity is scheduled to go on line November 1977.

Source: PEDCo Environmental Specialists, Inc. Summary Report, Status of Flue Gas Desulfurization Systems in the U.S., April-May 1977. Cinncinatti, OH: 1977, p. 219.

TABLE 3-130. NUMBER AND TOTAL MW OF FGD SYSTEMS
JUNE 1977

Status	No. of Units	MW
Operational	27	7,819
Under Construction	29	12,648
Planning		
Contract Awarded	20	9,797
Letter of Intent	5	1,892
Requesting/Evaluating Bids	5	3,565
Considering Only FGD Systems	33	14,856
Total	119	50,577

Source: PEDCo Environmental Specialists, Inc. Summary Report, Status of Flue Gas Desulfurization Systems in the U.S., April-May 1977. Cinncinatti, OH: 1977, p. 203.

Oxides of Nitrogen

Oxides of nitrogen are formed during fuel combustion by oxidation of the nitrogen in the air and the nitrogen in the fuel with air generally the major source. This oxidation occurs at high temperatures and the rate of formation increases with temperature. The primary form of NO_x control, therefore, is combustion modification to reduce temperatures and minimize NO_x formation. This is generally accomplished by staged firing, excess air control, water injection and other methods. Since flame temperature control is most important in NO_x control, some boiler designs produce significant quantities of NO_x and are not amenable to extensive control. An example of such a boiler is the cyclone boiler described earlier where the combustion rate and temperature are very high.

Catalytic scrubbers for NO_x removal have also been proposed. These units remove NO_x from stack gases after formation by reacting the NO_x to form other compounds capable of being disposed of more readily than the NO_x. An example is the formation of a dilute nitric acid stream in the scrubber. These scrubbers, however, are much more expensive than combustion modification.

Cooling

Selecting a suitable means of dissipating waste heat depends on a number of factors such as the quantity of heat to be dissipated, the availability of water, and local thermal pollution regulations. The four types of cooling systems are once-through cooling using fresh or saline water, cooling ponds, wet cooling towers, and dry cooling towers.

In once-through systems, water is withdrawn from some source, circulated through the condenser where it is heated, and then returned to the source. Once-through cooling systems are generally used where adequate supplies of water are available and no significant adverse effects on water quality are expected. Sources of water include rivers, lakes, estuaries, and the ocean. Once-through systems are normally more economical than other systems. The only consumptive water uses are those resulting from increased evaporation in the source water bodies because of the addition of heat.[1]

Where water supplies are limited and suitable sites are available, cooling ponds may be constructed so that water may be recirculated between the condenser and the pond. Sufficient inflow would be needed, either from upstream runoff or by diversion from another stream, to replace the natural evaporation induced by the addition of heat to the pond. A pond surface area of one to two acres per megawatt of plant capacity is normally required for dissipating the heat in the western states. However, pond size is very dependent on climate conditions. Cooling ponds are frequently used for other beneficial purposes, including recreation.[2]

Where conditions are not favorable for once-through cooling or for the construction of cooling ponds, cooling towers are generally employed for the dissipation of waste heat. Cooling towers may be used to provide full or partial cooling requirements during certain periods or throughout the year.

In wet cooling towers, the warm water is brought into direct contact with a flow of air, and the heat is dissipated principally by evaporation. Cooling towers may be either of natural- or mechanical-draft design. Because of the large structures involved and the added pumping and other costs, wet cooling towers are usually more expensive than once-through systems or cooling ponds.[3]

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[1] Jimeson, R.M. and G.G. Adkins. "Factors in Waste Heat Disposal Associated with Power Generation", Paper 26a, Presented at the 68th National AIChE Meeting, Houston, 1971.

[2] *Ibid.*

[3] *Ibid.*

Currently the largest natural draft wet cooling tower is about 450 feet in diameter and 450 feet high, and is adequate for an 800 Mwe plant. Wet cooling towers using forced draft are smaller because of limitations on fan diameters[1], and are constructed in multiple cells to cool large plants.

In a dry cooling tower, the water circulates in a closed system with the cooling provided by a flow of air created either by mechanical or natural draft, much like the radiator in an automobile. Because of the large heat transfer surface area and air volumes required, however, dry cooling towers are substantially more expensive than wet towers.

The amount of water "consumed" by the cooling process will depend on the specific plant design and the affected waterbody conditions.

3.8.3.2 Input Requirements

For illustrative purposes, a 3,000 Mw electrical generating facility has been chosen for quantifying the inputs associated with a power plant. The following sections discuss manpower requirements, material and equipment, costs, water needs, land usage, and ancillary energy requirements. The values reported below for manpower, materials and equipment and economics were extracted from Bechtel's "Energy Supply Planning Model".[1] The data were developed on the basis of well established technology and are considered to be accurate within +20, -10 percent.

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[1] Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

3.8.3.2a Manpower Requirements

Manpower estimates required for construction of a 3,000 Mwe power plant are shown in Table 3-131. The 3,000 Mwe facility will consist of 4 separate 750 Mwe boilers. Field construction is anticipated to last seven years with the first boiler completed at the end of the fourth year, the second boiler due to come on line at the end of the sixth year, and boilers number 3 and 4 to be finished during the seventh year. Table 3-132 lists the manpower resources required to operate and maintain the power plant.

3.8.3.2b Materials and Equipment

Table 3-133 lists the major materials and equipment needed for construction of four 750 Mwe boilers and associated generating and transforming equipment comprising a 3,000 Mwe power plant. This information was selectively extracted from "The Energy Supply Planning Model."[1]

3.2.3.2c Economics

Bechtel[2] has estimated capital costs of power plants in third-quarter 1974 dollars. From Bechtel data a cost estimate of $880 million has been derived for a 3,000 Mwe coal-fired power plant. The same data base indicates total annual utility costs of $4 million. This figure does not include the cost of the coal consumed since the power plant complex is a mine-mouth operation and the annual costs of producing the coal are accounted for in the mining operation. Using the manpower figures in

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[1] Carasso, M., *et al.* Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

[2] *Ibid.*

TABLE 3-131. SCHEDULE OF MANPOWER RESOURCES (MAN-YEARS) REQUIRED TO CONSTRUCT A 3,000 MW POWER PLANT

Skill	1	2	3	4	5	6	7
Civil Engineers	22	38	58	86	83	54	22
Electrical Engineers	16	28	43	63	60	39	16
Mechanical Engineers	13	22	33	49	47	31	13
Mining Engineers	0	0	0	0	0	0	0
Nuclear Engineers	0	0	0	0	0	0	0
Geological Engineers	0	0	0	0	0	0	0
Petroleum Engineers	0	0	0	0	0	0	0
Other Engineers	0	0	0	0	0	0	0
Total Engineers	51	87	134	198	190	124	51
Total Designers + Draftsmen	20	35	54	79	76	50	20
Total Supervisors + Managers	10	16	25	37	36	23	10
Total Technical	81	139	213	315	301	196	81
Total Non-Tech (Non-Manual)	39	66	102	150	144	94	39
Pipefitters	60	140	200	320	420	340	120
Pipefitter/Welders	27	63	90	144	189	153	54
Electricians	42	98	140	224	294	238	84
Boilermakers	45	165	150	240	315	255	90
Boilermaker/Welders	15	35	50	80	105	85	30
Iron Workers	21	49	70	112	147	119	42
Carpenters	21	49	70	112	147	119	42
Operating Engineers	15	35	50	80	105	85	30
Other Major Skills	0	0	0	0	0	0	0
Total Major Skills	246	574	820	1312	1722	1394	492
Other Craftsmen	18	42	60	96	126	102	36
Total Craftsmen	264	616	880	1408	1848	1496	528
Total Teamsters + Laborers	36	84	120	192	252	204	72
GRAND TOTAL	420	905	1315	2065	2545	1990	720

TABLE 3-132. MANPOWER RESOURCES REQUIRED TO OPERATE AND MAINTAIN A 3,000 MW POWER PLANT

Skill	Numbers
Electrical Engineers	16
Mechanical Engineers	8
Total Engineers	24
Total Designers + Draftsmen	4
Total Supervisors + Managers	56
Total Technical	84
Total Non-Tech (Non-Manual)	40
Pipefitters	32
Pipefitter/Welder	48
Electricians	48
Boilermaker/Welders	32
Other Operators	80
Total Major Skills	240
Total Craftsmen	240
Total Teamsters + Laborers	72
GRAND TOTAL	436

TABLE 3-133. SELECTED MAJOR MATERIALS AND EQUIPMENT REQUIRED FOR CONSTRUCTION OF A 3,000 MW POWER PLANT

Resource	Number
Refined Products (tons)	72,400
Ready Mixed Concrete (tons)	456,400
Pipe + Tubing (less than 24% D) (tons)	11,800
Pipe + Tubing (24% D + Greater) (tons)	1,200
Structural Steel (tons)	20,360
Reinforcing Bars (tons)	6,000
Valves (24% D + Greater) (items)	120
Valves (24% D + Greater) (tons)	100
Steam Turbogenerator Sets (1,000 hp)	4,280
Steam Turbines w/o Generators (1,000 hp)	120
Pumps + Drives (100 hp) (items)	140
Pumps + Drives (100 hp) (tons)	848
Heat Exchangers (1,000 sq. ft. surface)	600
Boilers (1,000,000 Btu/hr)	28,000

Source: Carasso, M., et al. Energy Supply Model, Computer Tape. San Francisco: Bechtel Corporation, 1975.

Table 3-123 and assuming an average annual wage of $15,000, then total annual operating costs excluding coal costs = $4 million + (436) ($15,000) = $10.5 million. It should be noted that since these values are in third-quarter 1974 dollars, price escalations for future years must be considered.

3.8.3.2d Water Requirements

The major consumer of water in a power plant is the cooling tower system. The make-up water for the cooling tower system replaces three losses - drift, blowdown, and evaporation. The magnitude of each of these losses is calculated from mass and energy balances around the cooling system by using the following assumptions or data.

1) 48% of input heat to the plant is sent to the cooling towers.

2) 90% of the heat to the cooling towers is dissipated via evaporation.

3) The heat of vaporization of water is 1050 Btu/lb.

4) The cooling water temperature rise across the steam condenser is 25°F.

5) Cooling tower drift losses are 0.02% of the cooling water circulation rate.

For a 3000 Mw power plant at 100% load factor and a 34% efficiency, the cooling tower makeup water requirements are 42,000 acre-ft per year. (See Section 3.8.3.3 for a more detailed description of facility size, efficiency, etc.) Other water losses include potable water, cleaning water, and other miscellaneous uses. These uses, however, are negligible compared to cooling tower usage. The process water used elsewhere in the plant has virtually no losses since all excess water (*e.g.*, boiler blowdown) is sent to the cooling tower as makeup water.

3.8.3.2e Land Requirements

A 1,000 Mwe coal-fired power plant requires 800 acres of land area. Linearly scaling to a 3,000 Mwe plant gives the land requirement as 2,400 acres. Within this 2,400 acres will be a 968 acre solar evaporation pond for cooling tower blowdown and a 228 acre limestone sludge disposal pit. These figures were determined for a 3,000 Mwe power plant at Gillette, Wyoming.

3.8.3.2f Ancillary Energy

There are no outside energy requirements for operation of a power plant.

3.8.3.3 Outputs

This section of the analysis considers the outputs from a 3,000 Mwe electrical generating facility design to burn coal from the Gillette, Wyoming vicinity. A description of this coal is shown in Table 3-134. The power plant is a new plant which utilizes a supercritical steam boiler system to drive steam turbines which in turn drive generators. A supercritical steam boiler operates at a temperature and pressure above the supercritical point of water.

TABLE 3-134. CHARACTERISTICS OF GILLETTE, WYOMING COAL

Location

Campbell County
Powder River Coal Field

Proximate Analysis, %

	Dry Basis	Avg.	Wet Basis
Moisture:	30.8 - 33.3	32.1	32.1%
Volatile:	39.0 - 47.7	43.4	32.2
Fixed C:	31.8 - 52.7	42.0	30.6
Ash:	6.0 - 8.9	7.5	5.1

Ultimate Analysis, %

Ash: 5.0 - 8.9
S: 0.3 - 0.8 - average = 0.55
H : 4.7 - 5.2
C: 45.7 - 74.5
N: 0.6 - 1.1
O: 16.1 - 40.5

Btu/lb (as received): 7,770 - 12,780 - avg: 10,275

Source: Evaluation of Low-Sulfur Western Coal. EPA-650/2-75-046. May 1975.

The efficiency of the power plant is assumed to be 34%. This efficiency is defined as the net electrical energy output of the plant divided by the energy input to the plant. Net electrical energy output is defined as gross electrical energy generated minus any plant auxiliary energy requirements. Although the cycle efficiency of the power plant is 38%, the overall net efficiency is 34% due to a usage of 4% of the gross electrical production by the lime/limestone scrubbers (see Sections 3.8.3.1 and 3.8.3.3a).

The load factor at the plant was assumed to be 100%. This value was chosen in order to quantify maximum daily emissions with the facility operating at capacity output. It should be noted, however, that load factors can vary greatly. Some power plants in areas of highly varying electrical demand have load factors lower than 50%.

The coal usage at this 3,000 Mw power plant burning 10,275 Btu/lb coal with an overall efficiency of 34% and a load factor of 100% is 35,180 tons per day.

3.8.3.3a Air Emissions

The only significant air emissions from a power plant come from the boiler flue gas produced during combustion of the plant's fuel. Emission rates of particulates, SO_2, NO_x, CO and hydrocarbons are calculated from fuel rates, fuel ash and sulfur contents and emission factors from "Compilation of Air Pollutant Emission Factors."[1] Carbon dioxide emissions are based on the theoretical combination of the coal analysis presented in Table 3-134.

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[1] U.S. Environmental Protection Agency. Compilation of Air Pollutant Emission Factors, 2nd ed., with supplements. Research Triangle Park, N.C.: Environmental Protection Agency, 1973.

The SO_2 and particulate emissions are assumed to be controlled by a limestone scrubbing unit. The particulates are 99 percent controlled by an electrostatic precipitator which precedes the SO_2 scrubber in the limestone scrubbing unit. The SO_2 emissions are 80% controlled in the scrubbing unit. Table 3-135 lists the air emissions resulting from these operations.

3.8.3.3b Water Effluents

Water effluents are calculated as suspended solids, total dissolved solids, and organic matter. Battelle[1] states that suspended solids and organic matter in power plant liquid wastes amount to 0.036 lb/10^6 Btu of fuel burned. Of this total 70% is suspended solids and 30% is organic matter. This factor and plant heat rates are used to calculate these two emissions. Total dissolved solids (TDS) are calculated by assuming that cooling tower blowdown, containing 10,000 ppm of TDS, is the main liquid effluent.

Using the above basis and a total blowdown rate of 1,400 gpm, 756 lb/hr suspended solids (1,000 ppm) and 324 lb/hr organics (460 ppm) are emitted with the cooling tower blowdown. At Gillette, Wyoming, of the 2,258 acre-ft/yr blowdown (1,400 gpm), 2,096 acre-ft/yr are sent to solar evaporation ponds and 162 acre-ft/yr are sent to SO_2 scrubbing as make-up water for the limestone scrubber.

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[1] Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle Columbus Laboratories, 1973.

TABLE 3-135. AIR EMISSIONS - 3,000 MW POWER PLANT BURNING GILLETTE, WYOMING COAL[1]

	Emissions/750 MW Boiler (lb/hr)	Total Plant Emissions (tons/day)
Particulates[2]	299	14.4
SO_2[3]	1,610	77.3
NO_x	6,580	316.0
CO	366	17.6
HC	110	5.3
Aldehydes	2	0.1
CO_2	1,600,000	76,800

Stack Parameters (per boiler)

Flow Rate (acfm)	Velocity (fps)	Height (ft)	Temp. (°F)	Diameter (ft)
2.56×10^6	60	500	180	30.0

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[1] Based on combustion of 35,180 TPD of 10,275 Btu/lb coal.

[2] Based on 5% ash and 99% control

[3] Based on 0.58% sulfur and 80% control.

3.8.3.3c Solid Wastes

The two primary types of solid waste produced at the power plant are ash from the boiler and electrostatic precipitators and sludge from the SO_2 scrubbers. The ash which is collected is the ash which enters the boiler in the coal and is not emitted out the stack (see Table 3-135). The ash collected at the 3,000 Mw power plant burning 35,180 tons per day of coal with 5 percent ash is 1745 tons per day. Concern has been raised about radioactive emissions from trace amounts of Radon 220 and 222 in coal ash. Concentrations are on the order of 10-20 of these materials, but emissions could be as high as 10 times background emissions depending upon coal composition and method of ash disposal.[1]

The quantity of scrubber sludge is determined on the basis of 80 percent SO_2 removal producing 90 percent $CaSO_3$ and 10 percent $CaSO_4$. In addition, the sludge contains a small amount of unreacted limestone (assumed to be 10 percent of the $CaCO_3$ which is reacted). The quantity of solids produced on this basis is 62,000 pounds per hour. These solids leave the sludge thickener in a 30 weight-percent solids water slurry and are sent to the settling pond. The slurry flow rate to the pond is 207,000 pounds per hour. Supernatant from the settling pond is removed as makeup water to the scrubbers at a rate which will maintain a 50 weight-percent solids sludge in the settling pond. The net flow to the pond (input sludge less withdrawn supernatant), therefore, is approximately 124,000 pounds per hour (1488 tons/day). It should be noted, however, that these wastes are disposed of on-site as part of the generation process.

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[1] Lee, Hong, *et al.* Potential Radioactive Pollutants Resulting from Expanded Energy Programs. EPA 600/7-77-082. Las Vegas, NV. U.S. Environmental Protection Agency, Office of Research and Development, Environmental Monitoring and Support Laboratory. 1977. p. 46, 124.

3.8.3.3d Noise Pollution

Noise emissions will be generated during both the construction and the operation phases of a coal-fired power plant. Sources of noise emissions during the construction phase are primarily associated with heavy duty construction equipment such as cranes, bulldozers, dump trucks, graders, air compressors, rock drills, pneumatic wrenches, and welding generators. The sound levels for each of these pieces of equipment range from 80 dBA for bulldozers and dump trucks to 98-99 dBA for rock drills and pneumatic wrenches. Total sound levels in the construction area will range from 89 dBA to 110 dBA.[1]

Principal noise sources for an operating coal-fired power plant include the cooling towers, pulverizer, coal pile bulldozers, coal car shakers, and rail car switching. Bulldozers and rail car switching will emit approximately 80 dBA. The cooling towers and pulverizer will emit approximately 104 dBA.

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[1] Battelle Memorial Institute, Columbus Laboratories. Detailed Environmental Analysis Concerning a Proposed Coal Gasification Plant for Trans-Western Coal Gasification Co., Pacific Coal Gasification Co., and Western Gasification Co., and the Expansion of a Strip Mine Operation Near Burnham, N.M. Owned and Operated by Utah International, Inc.

And the coal car shakers will emit approximately 101 dBA. Noise levels of 55 dBA will extned about one mile from the plant.[1,2,3]

3.8.3.3e Occupational Health and Safety

Data on injuries, deaths, and man-days lost are available from Battelle.[1] Converting from Battelle's basis of 10^6 Btu to a 3,000 Mwe power plant yields the following expected annual values: 0.77 deaths, 3.2 injuries, and 1,200 man-days lost.

SUMMARY

Table 3-136 presents a summary of the direct impacts associated with a 3,000 Mwe power plant in Gillette, Wyoming.

3.8.4 Social Controls

The regulation of conversion activities covers a wide range of technologies and residuals, including orderly development, environmental protection, health and safety, and regulation of product output. In the following section, the federal and state permit and regulatory structure over these activities will be discussed. These social controls will be described, beginning with Water Quality, Water Use, Air Quality,

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[1] Tracor, Inc. Guidelines on Noise. Washington, D.C.: American Petroleum Institute, 1973.

[2] Bolt, Beranek, and Newman. Noise from Construction Equipment and Operations, Building Equipment and Home Appliances. Cambridge, Mass.: Bolt, Beranek, and Newman, 1971.

[3] Swing, Jack W., and Donald B. Pies. Assessment of Noise Environments Around Railroad Operations, Report No. WCR 73-5. El Segundo, Calif.: Wyle Laboratories, 1973.

[4] Battelle Columbus and Pacific Northwest Laboratories. Environmental Considerations in Future Energy Growth. Columbus, Ohio: Battelle Columbus Laboratories, 1973.

TABLE 3-136. SUMMARY OF IMPACTS ASSOCIATED WITH A 3000 MW POWER PLANT AT GILLETTE, WYOMING

Input Requirements	
Manpower	
• construction phase	9,960 man years
• operation and maintenance	436 people
Materials and Equipment	
• refined products	72,000 tons
• ready mix concrete	456,000 tons
• piping	13,000 tons
• steel	26,000 tons
• steam turbogenerators	4 million hp
• boilers	28 billion Btu/hr
Economics[a]	
• capital cost	$880 million
• operating cost (excluding coal)	$11 Million
Water	42,000 acre-ft/year
Land	2,400 acres
Ancillary Energy	none
Outputs	
Air Emissions	
• particulates	14 ton/day
• SO_x	77 ton/day
• NO_x	316 ton/day
• CO	18 ton/day
• HC	5 ton/day
• Aldehydes	0.1 ton/day
• CO_2	76,800 ton/day
Water Effluents	
• to zero discharge solar evap. ponds	2,096 acre-ft/year
Solid Wastes	
• ash	1,745 ton/day
• FGD scrubber sludge	1,488 ton/day
Noise Pollution	minimal
Occupational Safety and Health	
• fatalities	0.77 deaths
• injuries	3.2 injuries
• loss time	1200.0 man-days

[a] third quarter 1974 dollars

Solid Waste, Noise, Safety and the Regulation of Product Output. A generalized flow diagram of the sequence of regulator procedures dealing with processing is shown in Figure 3-32.

3.8.4a Water Quality

Regulation of coal conversion facilities for water discharges can occur at the state and federal level. The provisions for this regulation have been described in the section on generally applicable regulations, which identified the Federal Water Pollution Control Act of 1972 (FWPCA) as the major legislation affecting water discharges.

The requirements of FWPCA do not supersede water quality standards affecting navigation under the 1899 Rivers and Harbors Act. Thus, the Army Corps of Engineers still issues permits for constructing discharge into navigable waterways, and EPA issues permits on the use of such discharges.[1] The FWPCA provides for establishing a system of permits that are issued either by EPA or by the states with EPA approval. The permit must specify the substance to be discharged and how and when water quality will be improved.

The technologies described in Section 3.8 have been designed for zero discharge. If discharges were to be made, the above laws would be applicable, in addition to appropriate state regulations and permit programs.

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[1] Environment Information Center. "Water Pollution" in Environment Regulation Handbook. New York: Environment Information Center, 1973, Water Int. 3.

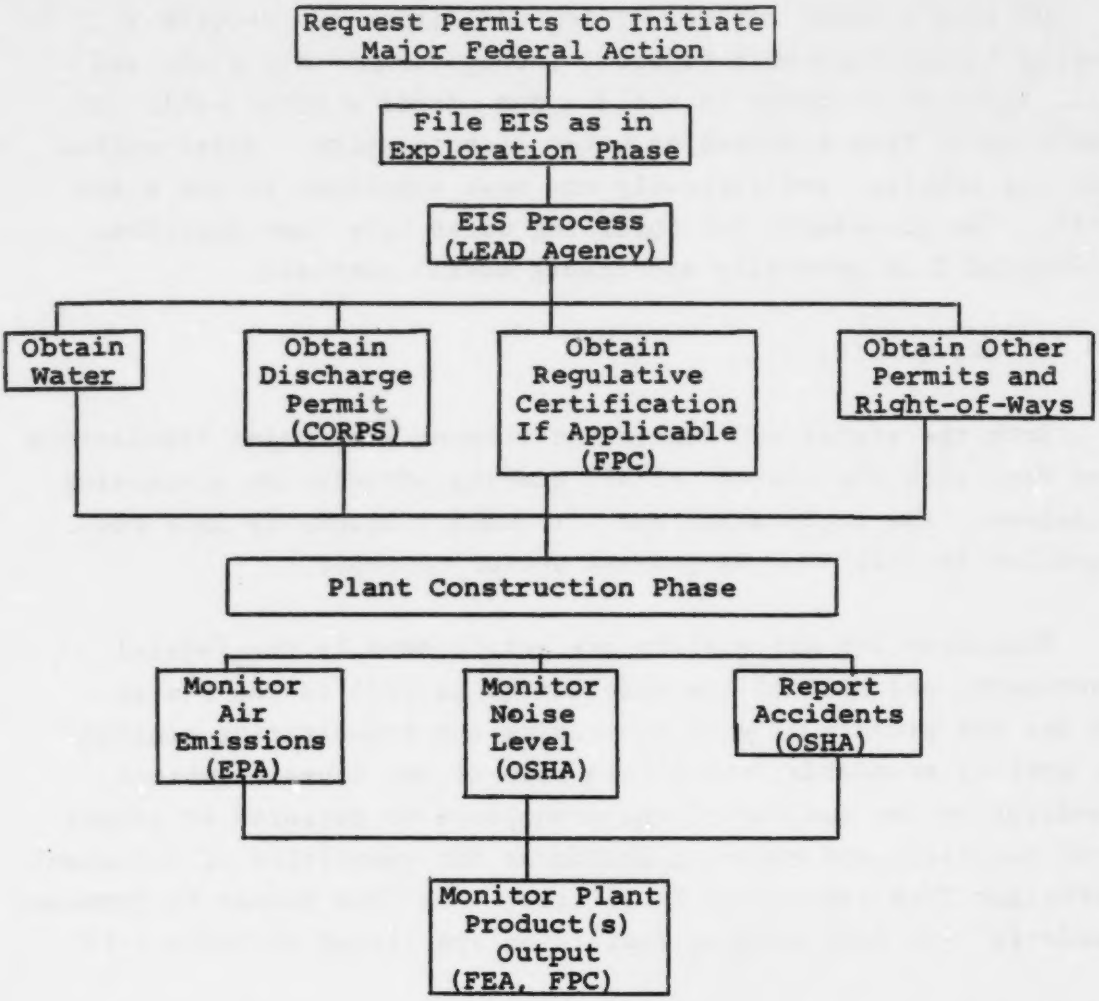
Request Permits to Initiate Major Federal Action
File EIS as in Exploration Phase
EIS Process (LEAD Agency)
Obtain Water
Obtain Discharge Permit (CORPS)
Obtain Regulative Certification If Applicable (FPC)
Obtain Other Permits and Right-of-Ways
Plant Construction Phase
Monitor Air Emissions (EPA)
Monitor Noise Level (OSHA)
Report Accidents (OSHA)
Monitor Plant Product(s) Output (FEA, FPC)

Figure 3-32. Processing Procedures

3.8.4b Water Use

Obtaining water for conversion facilities can require a complex interaction with federal, intergovernmental, state and local agencies in order to build a dam, drill a water well, or remove water from a stream or water district pipe. Water rights laws are complex, and typically are most important at the state level. The procedures for obtaining water have been described in Chapter 2 on generally applicable social controls.

3.8.4c Air Quality

Both the states and federal government have major regulations that deal with the control of air quality affected by processing emissions. The legislation and air quality standards have been described in Chapter 2 on general social controls.

Standards for air quality are established by the federal government, and most of the enforcement is left to the states. EPA has the primary role in developing and promulgating minimum air quality standards, which have been of two types: ambient standards on the quality of the atmosphere as measured at ground level (usually) and emission standards for quantities of pollutant discharges from processing facilities. The "New Source Performance Standards" for coal burning facilities are listed in Table 3-137.[1]

3.8.4d Solid Wastes

Much of the disposal problem in coal processing facilities deals with the disposal of ash, slag or other chemical by-products (sulfur, calcium sulfate, etc.). Solid wastes, however, are the

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[1] Emission standards for liquefaction and gasification plants have not been established.

TABLE 3-137. FEDERAL NEW SOURCES OF COAL BURNING EMISSION STANDARDS

Contaminant	Quantity (1 pound per million Btu)
Sulfur Dioxide	1.2
Nitrogen Oxides	0.7
Particulates	0.1
Opacity (percent)	20.0

Source: U.S., Department of the Interior, Bureau of Reclamation. El Paso Coal Gasification Project, New Mexico: Draft Environmental Statement. Salt Lake City: Bureau of Reclamation, Upper Colorado Region, 1974.

major form of pollutant for which the federal government has not set standards. Much of the problem is handled by the state governments, as has been described in Chapter 2 on general social controls. Also noted in the general social controls are the impacts of the air and water laws on solid waste disposal.

3.8.4e Noise

Noise control is under the jurisdiction of both the Occupational Health and Safety Administration (OSHA) and the Environmental Protection Agency (EPA). OSHA standards and enforcement deal primarily with worker exposure, whereas EPA standards cover a broader area. The Federal Power Commission (FPC) requires that above ground compressors must be located and treated to reduce noise impacts.[1]

Noise control standards were established by the Occupational Health and Safety Act of 1970 (OSHA) and are also referenced by the Federal Coal Mine Health and Safety Act[2] (see section on mining social controls). Procedures for enforcing the OSHA standards are described in the following section on safety. Current noise standards are shown in Table 3-138. If these standards are exceeded some protection must be provided against the effects of noise exposure. In addition to the standards listed, noise from impulses or impacts are not to exceed 140 decibels (dB).

3.8.4f Safety

Coal processing activities usually involve high temperatures

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[1] 18 CFR 2.69.

[2] Federal Coal Mine Health and Safety Act of 1969, 15 USC Sections 633.636; 30 USC Sections 801-804, 811-821, 841-846, 861-878, 901, 902, 921-924, 931-936, 951-960; 83 Stat. 742.

TABLE 3-138. OSHA NOISE LEVEL STANDARDS[a]

Noise Duration (hours/day)	Maximum Sound Level (Decibels)
15 minutes	115
30 minutes	110
60 minutes	105
90 minutes	102
2 hours	100
3 hours	97
4 hours	95
6 hours	92
8 hours	90

[a] Maximum values without ear protection.

Source: U.S., Department of the Interior, Bureau of Reclamation. El Paso Coal Gasification Project, New Mexico: Draft Environmental Statement. Salt Lake City: Bureau of Reclamation, Upper Colorado Region, 1974.

and pressures and expose workers and others in the immediate area of the plant to hazards from equipment failure or misuse. A number of federal, state and industrial regulations deal with these safety problems:

Federal

Federal jurisdiction over processing safety is derived largely from the Occupational Safety and Health Act of 1970[1] and the Natural Gas Pipeline Safety Act of 1968[2]. The Departments of Labor and Health, Education and Welfare (HEW) have the major responsibilities under OSHA. HEW makes working condition evaluations and provides technical assistance to employers, and Labor is responsible for enforcement. The Office of Pipeline Safety within the Department of Transportation is responsible for promulgation and enforcement of most interstate gas transmission facilities, and apparently has some jurisdiction over coal gasification projects. The Occupational Safety and Health Administration has developed an extensive and complex set of standards and regulations.

Enforcement of the standards is handled by the Assistance Secretary for Occupational Safety and Health, who has most of the ultimate decision making authority. There are four sets of standards: (1) general industry standards, (2) special industry standards, (3) construction safety standards, and (4) maritime standards. Although the major elements of the standards are published in four sections of the Code of Federal Regulations, many of the standards refer to the American National Standards Institute (ANSI) "national consensus standards"[1]. Significant research efforts are currently underway to refine and develop additional standards in many areas, and much of this work is conducted by the National Institute for Occupational Safety and Health (NIOSH) under HEW. Apparently some of this research is applicable to emerging coal conversion technologies.

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[1] Occupational Safety and Health Act of 1970, 5 USC Sections 5108, 5314, 5315, 7902; 15 USC Sections 633, 636, 1 8 USC Section 1114; 29 USC Sections 553, 651-678; 42 USC Section 3142-1; 84 Stat. 1590.

[2] Natural Gas Pipeline Safety Act of 1968, 49 USC Section 1671, 82 Stat. 720.

States

Prior to the passage of the Occupational Safety and Health Act, most of the responsibility for worker safety rested with the states. The states may enforce the OSHA standards, but they will be preempted if they fail to do so.[2] At the present time, only Colorado, Utah and Wyoming in the 8-state region have operating OSHA plans.

Industry

Processing plant design and safety features usually employ company manuals of engineering standards, current refinery codes and power piping codes. These codes are primarily standards established by the American Standards Institute (ANSI) which develops the consensus standards frequently referenced by OSHA.[3]

Mallino, David L., and Shaun M. Werner, eds. Occupational Safety and Health: A Policy Analysis. Washington: Government Research Corporation, 1973, p. 10.

U.S., President. Report on Occupational Safety and Health. Washington: Government Printing Office, 1972, p. 35.

U.S., Department of the Interior, Bureau of Reclamation. El Paso Coal Gasification Project, New Mexico: Draft Environmental Statement. Salt Lake City: Bureau of Reclamation, Upper Colorado Region, 1974, p. 4-41.

3.8.4g Regulation of Product Output

Under certain circumstances the output of processing facilities is regulated by federal and state energy agencies or regulator commissions. The applicability of these regulations is uncertain at this time, and may be dependent on policies developed in the near future. Apparently neither the Interstate Commerce Commission (for liquid and solids) nor the Federal Power Commission (for gas) is presently exercising jurisdiction over price or supply distribution of synthetic fuels except as these relate to pipelines or other transportation systems.

The regulation of product output and distribution, as well as the use of raw energy inputs has recently become a major element of federal energy regulation. These activities were initially accomplished by the Federal Energy Office (FEO) and are now the responsibility of the Department of Energy (DOE)[1]. DOE has broad regulatory powers over the allocation of petroleum, but apparently has less authority over the use and price of coal. DOE has, however, issued regulations under which it may allocate and price low sulfur coal to such processing facilities as electric power generation facilities. Although it can control the product mix of petroleum processing facilities (*i.e.*, refineries), it is not known at this time if it would exercise similar authority over synthetic fuels facilities.

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[1] Energy Supply and Environmental Coordination Act of 1974, 15 USC Section 791 *et seq.*, 42 USC Section 1857, 88 Stat. 246.

3.8.4h Other Requirements

Components of processing facilities may involve a number of additional agencies or regulator precedures. For example, these facilities are frequently somewhat isolated and require radio-communication facilities and permits from the Federal Communication Commission for the construction and operation of such facilities. Large scale operations may require health permits for food or hospital facilities. Of course, business and tax permits need to be acquired, usually with state Revenue Departments or Corporation Commissions. Details of these permits and regulatory arrangements will not be covered in this chapter..

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